CANADA

NATIONAL ENERGY BOARD

In the Matter of a Public Inquiry
Into Matters Relating to the

Northern Canada Power Commission

June 1985

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Cat. No. NE22-3/1985-1E
ISBN 0-662-14111-3

This report is published separately in both official languages.

Ce rapport est publié séparément dans les deux langues officielles.

Copies are available on request from:

Regulatory Support Office
National Energy Board
473 Albert Street
Ottawa, Canada
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Exemplaires disponibles auprès du:

Bureau du soutien de la réglementation
Office national de l'énergie
473, rue Albert
Ottawa (Canada)
K1A 0E5
(613) 998-7204

Printed in Canada

Imprimé au Canada

Recital and Appearances

IN THE MATTER OF the National Energy Board Act and subsections 22(2) and 20(3) thereof;

IN THE MATTER OF an inquiry into matters relating to the Northern Canada Power Commission under File No. 1970-3/N28-1

HEARD: At Whitehorse, Yukon on 4, 5, 6, 7, 8, 9, 11 and 12 February 1985, and at Yellowknife, Northwest Territories on 4, 5, 6, 7, 8, 11, 12 and 13 March 1985.

BEFORE:

J.R. Hardie	Presiding Member
W.G. Stewart	Member
E.S. Bell	Member
J.M. Heath	Member
R.A. Laking	Member

APPEARANCES:

H.D. Williamson	Northern Canada Power Commission
M. Hampton	Association of Yukon Communities
P. Jenkins	City of Dawson
T. Gorrel	City of Whitehorse
K. Anderson	City of Yellowknife
C. Johnson L. Pettijohn	Cominco Ltd. & Pine Point Mines Limited
M.V. McDill G.D. Baker	Cyprus Anvil Mining Corporation
P.L. Miller	Esso Resources Canada Limited
D. Fox	Frobisher Bay Chamber of Commerce
J.G. Gilmour	Government of the Northwest Territories
W. Smart	Government of Yukon
J. Carstairs	ICG Utilities (Plains - Western) Ltd.
D. Hill	Inuvik Chamber of Commerce
J. Anawak	Keewatin Chamber of Commerce
A. Berger O.C. Paton	Residents in Dawson
F. Roberts	Resident in Whitehorse
C.A. Dent	Northwest Territories Association of Municipalities
T.H. Detlor	Town of Inuvik
T.A. Dickson	United Keno Hill Mines Limited
B. Woloshyniuk	Whitehorse Chamber of Commerce
W. Lengerke	Yukon Chamber of Mines
C.K. Sheard	Yukon Electrical Company Limited
M. Byblow	Yukon New Democratic Party
P. Nugent	Yukon Teachers' Association
J. Morel	Board Counsel

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Appendices

Abbreviations

AFUDC	Allowance for Funds Used During Construction
APPA	American Public Power Association
B.C. Hydro	British Columbia Hydro and Power Authority
BTU	British Thermal Unit
CAMC or Cyprus Anvil	Cyprus Anvil Mining Corporation
Cominco	Cominco Ltd.
Con	Con Mine
Dome	Dome Petroleum Limited
GNWT	Government of the Northwest Territories
GW.h	Gigawatt hour (1 000 000 kW.h)
ICG	ICG Utilities (Plains-Western) Ltd.
kV	kilovolt
kV.A	kilovolt ampere
kW	kilowatt
kW.h	kilowatt hour
MW	megawatt (1 000 kW)
MW.h	megawatt hour
NARUC	National Association of Regulatory Utility Commissioners
NCPC or the Commission	Northern Canada Power Commission
NCPC Act	Northern Canada Power Commission Act
NEB or the Board	National Energy Board
NEB Act	National Energy Board Act
NWT	Northwest Territories
Pine Point Mines	Pine Point Mines Limited
UKHM or United Keno Hill Mines	United Keno Hill Mines Limited
YECL or Yukon Electrical	Yukon Electrical Company Limited
YTG	Government of Yukon

Definitions

Administered Prices Guidelines	"6 and 5" restraint program
Allocation of Costs (Allocating)	In a fully distributed cost of service study, the assignment of classified costs to customer classes of service using prescribed allocation techniques.
August 1983 report	National Energy Board, In the Matter of a Public Inquiry Into Matters Relating to the Northern Canada Power Commission (August 1983).
Base Year	The period of twelve consecutive months ending on the last day of the most recent fiscal year for which actual financial information is available. For the purpose of this inquiry, the base year is the period 1 April 1983 to 31 March 1984.
Classification of Costs (Classifying)	In a fully distributed cost of service study, the process of classifying functionalized costs jointly used by customer classes to demand, energy and customer-related cost components for allocation to customer classes so that unit demand, energy and customer costs may be determined for each customer class.
Coincident Peak Demand Method	Allocation of the demand-related costs to customer classes in accordance with the demand of each customer class at the time of system peak.
Customer Cost (Component)	Costs that are deemed to be related to and vary with the number of customers, such as meters, meter reading, service equipment and a portion of distribution.
Demand Cost (Component)	Costs that are related to and are deemed to vary with power demand (i.e., kW), such as a portion of production, transmission and distribution costs.
Elasticity of Demand	The ratio of the percentage change in quantity demanded for a good to the percentage change in price, keeping everything else constant. Demand is elastic when the absolute value of the ratio exceeds 1.0 and inelastic when it is less than 1.0. Demand is used here as an economics term (i.e., the quantity of a good required by consumers) rather than as an engineering term (kilowatts), so that there can be a price elasticity of demand for energy and a price elasticity of demand for power.
Energy Cost (Component)	Costs, such as for fuel, that are related to and vary with energy production or consumption.
Equalized Rates (as referred to by NCPC in the 1983 inquiry)	All customers of the same class in a territory are charged identical rates.
Federal Regulatory Agency (or Body)	the single federal regulatory agency (or body) recommended to regulate NCPC.
Functionalization of Costs (Functionalizing)	In a fully distributed cost of service study, the preliminary arrangement of costs according to functions performed by the electric system. Major functions performed by the electric system are production, transmission and distribution. Subfunctionalization is the breakdown of major functions into specific cost-incurring activities. Functionalization is largely accomplished by the use of a uniform system of accounts.

The functionalization process also involves separating various costs between voltage levels or other breakdowns which assist in the classification of costs.

Hydro Rate Stabilization Fund (Hydro Stabilization Fund) — In systems having hydroelectric and thermal generation, a reserve fund established by collecting in high-water years revenue from customers which exceeds the cost of providing service. This provides a cushion or financial reserve to be drawn down in low-water years thereby providing more stable rates from year to year.

Interim Year — An interim year is the year between the base year and the test year. For the purpose of this inquiry, the fiscal year 1 April 1984 to 31 March 1985.

Life-line Rate — The life-line rate structure prices the first block of energy consumption at some affordable rate and is of a size that approximates the energy requirements "essential" to basic human needs.

Load Factor — The ratio of the average load in kilowatts supplied during a designated period to the peak or maximum load in kilowatts occurring in that period. Load factor, in percent, also may be derived by multiplying the kilowatt hours in the period by 100 and dividing by the product of the maximum demand in kilowatts and the number of hours in the period.

Noncoincident Peak Demand Method — Allocation of the demand-related costs to customer classes in accordance with the peak demand of each individual class irrespective of the class demand at the time of system peak.

Rate Rationalization — Rationalization of rates as was described by a witness for NCPC in the 1983 Inquiry, "Rationalized rate structure is the terminology applied by the Commission, primarily in the Northwest Territories rate zone, wherein the present multiplicity of rate structures applicable to each specific community or area served would be gradually eliminated in favour of a smaller number of common rate structures applicable to specific communities and/or rate zones in the NWT, taking into consideration the type of generation available for supply."

Test Year — A period of twelve consecutive months that is representative of the period when the new rates would probably be in effect. For the purpose of this inquiry, the test year is the fiscal year 1 April 1985 to 31 March 1986.

the North/North of 60° — Yukon and the Northwest Territories.

the territorial public utilities boards/the territorial boards — Yukon Utilities Board and the Public Utilities Board of the Northwest Territories.

Thirteen-month Average — A 13-month average is obtained by aggregating the opening balance for the test year and the balances at the end of each month in the test year and dividing the total by 13.

Value-of-Service Price — The maximum price that a customer is prepared to pay for a given product or service having regard to his desire for the product or service and his ability to pay.

Wheeling — The use of the transmission facilities of one system to transmit power of and for another system.

Chapter 1
Introduction

During June and July 1983, the National Energy Board held an inquiry pertaining to the Northern Canada Power Commission (see Appendix A for background information concerning NCPC). That inquiry was held at the request of the Minister of Energy, Mines and Resources following a request to him from the Minister of Indian Affairs and Northern Development who was responsible for NCPC. The Minister of Indian Affairs and Northern Development asked that the NEB review and advise him on the determination of the cost of service, rate design, general principles of rate making and the method of regulation of NCPC, as well as on whether any changes to the NCPC Act would be needed regarding the determination of rates.

In clarifying the objectives of that inquiry, the Board indicated in its opening statement that it did not intend to determine the revenue requirement nor the exact rates to be charged by NCPC but rather that it intended to deal with policies and principles that should be adopted in relation to NCPC in order to meet the requirements of public accountability and financial responsibility to the federal government.

In its August 1983 report entitled "In the Matter of a Public Inquiry Into Matters Relating to the Northern Canada Power Commission", the Board made a number of major recommendations concerning corporate structure and operations, framework for regulation, revenue requirements, capitalization, approval and funding of major projects, and rate design. A summary of these recommendations is set out in Appendix B.

The current report has been prepared in response to a further request made by the Minister of Indian Affairs and Northern Development, in 1984, to the Minister of Energy, Mines and Resources, wherein he sought the assistance of the National Energy Board to provide him with more specific advice on rate matters pertaining to the Northern Canada Power Commission.

In order to gain the necessary information from which to write this report, the National Energy Board held an inquiry set down by its Order No. EHR-1-84 (see Appendix C) as subsequently amended by Order Nos. AO-1-EHR-1-84 (see Appendix D) and AO-2-EHR-1-84 (see Appendix E). The inquiry looked into matters concerning the revenues of the Northern Canada Power Commission and the determination of cost-based rates which may be charged by NCPC from 1 April 1985 to 31 March 1986 inclusive.

The inquiry was conducted pursuant to subsection 22(2) of the National Energy Board Act. The subject matter of the inquiry is set out in detail in Appendix I to Board Order No. EHR-1-84 and concerned generally an examination of the proposed rate zones of NCPC and of the proposed rate base, revenue requirement and rate design for each such rate zone for the test year 1 April 1985 to 31 March 1986 with a view to making appropriate recommendations on NCPC's rates.

As required by Paragraph 3 of Order No. EHR-1-84, the Northern Canada Power Commission filed with the Board on 19 October 1984 a submission together with supporting written direct evidence. This material was prepared by NCPC to address the subject matters of the inquiry as set out in Appendix I to Order No. EHR-1-84. In addition to the subject matters set out in Appendix I, the material also addressed the matter of equity financing.

Although the Board conducted the inquiry under Part II of its Act, it approached the examination of NCPC's submission in the light of the principles the Board has adopted pursuant to Part IV of its Act for determining the rates to be charged by utilities under its jurisdiction.

NCPC was required to file a rate design based upon the Board's recommendation, set out in Section 4.4 of its August 1983 report, that in each of the territories there should be two rate zones for the supply of electricity: a hydro rate zone and a diesel rate zone.

The Board examined NCPC's rate base, particularly with regard to facilities used to provide service, and whether expenditures related to particular facilities were prudently incurred and, therefore, whether their

costs should be recovered from NCPC's customers. Where NCPC's facilities have been used to supply service since prior to the base year 1 April 1983 to 31 March 1984, the Board did not believe that it would be useful to question the basic decisions to install those facilities but was willing to hear evidence as to the prudence of the costs incurred.

The Board required NCPC to file details of depreciation, including accumulated depreciation, determined on a straight-line basis as recommended by the Board in its August 1983 report. However, the Board indicated that it was willing to consider evidence and submissions on methods of depreciation of assets other than straight-line over useful life.

Similarly, the revenue requirement of NCPC for the test year was examined for each rate zone. The cost of service items the Board considered included, but were not limited to, operating and maintenance costs, fuel costs, depreciation rates and resulting charges for depreciation of plant, head and regional office costs and the allocation thereof, and return on rate base.

For the purpose of this inquiry, the return on rate base was considered to be the cost of debt related to used and useful assets. Although the Board recommended in its August 1983 report that the Commission should have some equity financing, the Board considered that its mandate in this inquiry was to inquire into and report on revenues and rates of NCPC as it is currently constituted. The Board, therefore, did not hear or take notice of evidence concerning the possible future role of equity in the capital structure of NCPC and the rate of return which should be allowed on such equity.

Finally, the Board examined rate design proposals for each rate zone. Specifically, the Board explored the relationship between the revenue requirement and the rates proposed by NCPC for the customer classes in each rate zone.

The Board's objective in the inquiry was to determine fair rates based on the cost of providing service. Whether and to what extent these rates should be subsidized was considered to be outside the scope of the inquiry.

The inquiry commenced on 4 February 1985 in Whitehorse, Yukon and sat each day, with the exception of 10 February 1985, until 12 February 1985. The inquiry recommenced on 4 March 1985 in Yellowknife, Northwest Territories and concluded on 13 March 1985 having sat daily excluding 9 and 10 March 1985.

Oral evidence and written submissions were received from a variety of interested parties, including the territorial governments, municipalities, electric utilities, mining companies, business associations, public interest groups and individuals.

Chapter 2
Summary of Major Recommendations

Having reviewed the requirements of the NCPC Act, the Board finds that rates set pursuant to the NCPC Act would not be just and reasonable using criteria normally followed by the Board in setting utility rates. For example, the Act does not recognize depreciation per se but instead prescribes that NCPC collect in its rates funds sufficient to make principal repayments on all outstanding loans regardless of whether the loans are related to assets actually in service. This and other provisions in the NCPC Act prompted the Board to recommend in its August 1983 report that the rates for NCPC be set using the rate base/rate of return methodology to determine revenue requirement. The Board also recommended that NCPC calculate depreciation expense on a straight-line basis and that separate revenue requirements be determined for a hydro zone and a diesel zone in each territory.

NCPC's 19 October 1984 submission, the subject of this inquiry, followed the rate base/rate of return approach to determine the test year revenue requirement. It also made use of a fully distributed cost of service study to design rates.

Having reviewed NCPC's submission with regard to regulatory practices and rate regulation concepts, it is the Board's finding that a number of adjustments are required to ensure just and reasonable cost-based rates. The rates calculated by the Board based on its findings are just and reasonable in a regulatory sense; however, it is evident that some of the resultant rates could be at levels unaffordable to various customers and/or communities served by diesel generation. While the questions of whether and to what extent these rates should be subsidized were outside of the scope of the inquiry, the Board observes that there clearly appears to be an ongoing need for some form of subsidization in the North.

The Board's major recommendations are outlined below.

Whitehorse No. 4

NCPC included, in its Yukon hydro rate zone rate base, a generating unit at Whitehorse Rapids called Whitehorse No. 4. This unit, placed in service in 1984, was included in NCPC's test year plant in service at a cost of approximately $61,300,000. However, because market conditions have not materialized as originally anticipated, Whitehorse No. 4 is expected to be superfluous to the test year generation requirements of the system. The Board, therefore, considers that Whitehorse No. 4 cannot be strictly viewed as being "used and useful" and recommends that Whitehorse No. 4 be removed from rate base and established as an "asset specially classified". However, the Board notes that NCPC is actually using Whitehorse No. 4 for base load generation on the system as it is the most efficient unit at Whitehorse. The Board, therefore, recommends that NCPC be allowed depreciation expense on Whitehorse No. 4. However, the Board recommends that no return be allowed on Whitehorse No. 4 until its output is considered to be required to meet some portion of the system load, at which time the undepreciated capital cost of Whitehorse No. 4 should be phased into rate base. (See Section 4.2)

Aishihik Power Plant

NCPC included the full cost of constructing its generating facility at Aishihik in its Yukon hydro rate zone rate base. The major portion of this unit was constructed during the period 1973 through 1976. The project experienced significant cost overruns, evidenced by final costs of approximately $39,300,000 compared to original estimates of approximately $16,800,000. Having considered the information contained in two reports which were written on the cost overruns and having given regard to the evidence presented during the inquiry, the Board recommends that approximately $10,200,000 related to Aishihik be removed from the test year rate base. (See Section 4.3)

Asset Lives of Hydroelectric Production Plants

NCPC assumed, for the purposes of its submission, asset lives for its hydroelectric production plants of 30 to 50 years. The Board recommends that 65 years be used in the test year for all hydro plants

except Mayo, and that NCPC retain the services of a consultant to perform a depreciation study. (See Section 4.5)

Inuvik Powerhouse Destroyed by Fire

In 1983, NCPC's 25-year old powerhouse at Inuvik was destroyed by fire. Its net book value at the time was approximately $595,000. The powerhouse was replaced in the interim year 1 April 1984 to 31 March 1985 at a cost of approximately $6,000,000, with the cost being fully covered by insurance proceeds. NCPC included the $6,000,000 in its test year rate base. The Board recommends that the excess of insurance proceeds over the net book value of the assets destroyed be recorded as a deferred credit to act as an offset to the $6,000,000 recorded as original cost. (See Section 4.6.3)

Transmission Line to Johnson's Crossing

NCPC's submission also reflected NCPC's expectation that it would, during the interim year, construct an $800,000 transmission line from Whitehorse to Johnson's Crossing, thereby interconnecting Johnson's Crossing to the hydro system. NCPC therefore included Johnson's Crossing in the Yukon hydro rate zone. The Board notes that the transmission line was not built during the interim year. The Board does not believe that NCPC will build the transmission line during the test year and has therefore removed the projected cost of the transmission line and associated accumulated depreciation from the Yukon hydro rate zone rate base. The Board believes however that Johnson's Crossing may become interconnected to the hydro system by a distribution line to be constructed by Yukon Electrical Company Limited (YECL) and therefore has left Johnson's Crossing in the Yukon hydro rate zone. Nonetheless, the Board recommends that, as long as Johnson's Crossing continues to be served by NCPC via diesel generation, NCPC's customers at Johnson's Crossing should be charged the rates designed for the Yukon diesel rate zone. (See Sections 4.7, 6.2.4 and 8.2)

Rate of Return

For the purpose of this inquiry, the Board instructed NCPC to calculate its rate of return as the cost of debt related to used and useful assets. In this regard, the Commission determined a composite interest rate for debt. This rate was applied to the rate base of each of NCPC's cost centres and rate zones.

The Board is of the view that using a composite interest rate is appropriate for NCPC. However, the Board is of the view that, on a corporate basis, the total of loans outstanding used in calculating the test year composite interest rate should equal the test year rate base. In order to achieve this result, the Board recommends that various loans be deferred or forgiven by the federal government and deferred or written off, as applicable, by NCPC. In conjunction with its rate base recommendations, the Board recommends that:

1. NCPC's interest-free loan of $7,500,000 be incorporated into the calculation of the composite interest rate;
2. $1,850,000 of loans outstanding re Whitehorse No. 4 be foregiven and the remaining loans outstanding re Whitehorse No. 4 be deferred and excluded from the determination of the test year composite interest rate calculation;
3. loans associated with those costs removed by the Board from rate base for Aishihik cost overruns be forgiven and written off;
4. loans associated with assets not in service be forgiven and written off; and
5. loans in respect of under-recovery of depreciation be forgiven and written off, to the extent required in order to make loans outstanding equal rate base. The under-recovery of depreciation results from the restatement of NCPC's accumulated depreciation to a straight-line basis from the mixed straight-line and annuity basis that had been used by NCPC to coincide with loan repayments.

After giving effect to its various recommendations regarding rate of return, the Board recommends that a rate of return on rate base of 8.64 percent (as compared to the rate of 10.1984 percent included in NCPC's submission) be used for the test year. (See Chapter 5)

Operating and Maintenance Expenses

In response to various information requests, NCPC filed numerous tables in support of its forecast test year operating and maintenance expenses. Large increases were projected from the base year in certain functions whereas decreases were projected in others. In the base year, because Canada's Administered Prices Guidelines applied to NCPC's rates, NCPC deferred various maintenance programs in an effort to control its costs. NCPC stated that it had also introduced refinements in its test year budgeting procedures. These factors hampered the ability to compare base year and test year levels of expenditure in order to determine the reasonableness of the test year forecasts. However, evidence was introduced showing NCPC's "actual to budget" record for

the past few years. In light of this evidence, the Board recommends that NCPC's estimates for test year supply and services, and travel expenses be reduced by three percent. (See Sections 6.2 to 6.6)

Allocation of Head and Regional Office Costs

In its submission, NCPC allocated the head and regional office revenue requirements to each rate zone in proportion to the zone's direct salaries and wages. This method represented a departure from the method NCPC had been using. The Board does not believe that salaries and wages is an appropriate basis on which to allocate all head and regional office costs. The Board therefore recommends that, in future, NCPC identify each head and regional office function and determine an appropriate allocation base for each. For the test year, however, the Board accepts NCPC's proposed allocation base of salaries and wages for all functions, with the following exceptions. The Board believes that NCPC's method is inappropriate for assigning interest income earned on temporary cash investments and in addition, that it results in unacceptable increases in head and regional office costs allocated to the NWT heat and water & sewerage rate zones. The Board believes that it would be more appropriate to allocate interest income to the various rate zones in proportion to the rate base for each rate zone. The Board also recommends that the amounts allocated for the test year to the heat and water & sewerage rate zones be determined by escalating the amounts of head and regional office costs allocated to these zones in the base year by the percentage increases from the base to test year in head and regional office revenue requirements respectively. (See Sections 6.6 and 6.7)

Fully Distributed Cost of Service Study

After having determined the revenue requirement for each rate zone, NCPC's first step towards designing rates was the completion of a fully distributed cost of service study. Such a study functionalizes, classifies, and allocates costs so that revenue requirements can be determined for each customer class in a rate zone. The major issues regarding NCPC's proposed cost allocation are described below.

Classification of Production Plant

NCPC classified production plant as 100 percent demand-related. The Board finds this acceptable for diesel production plant. However, the Board recommends that hydro production plant and hydro production operating expenses be classified as 80 percent demand and 20 percent energy. (See Sections 7.3.1 and 7.3.2)

Secondary (Interruptible) Class

In its cost allocation, NCPC allocated only energy-related costs to the secondary (interruptible) class. Doing so resulted in a proposed rate for the class of 0.961¢ per kW.h as compared to the present rates of 3.36¢ per kW.h for the Whitehorse Hospital and 2.478¢ per kW.h for United Keno Hill Mines Limited (UKHM). This raised the issue that NCPC had under-allocated costs to the interruptible class and that the resulting rate was significantly too low. After reviewing the evidence, the Board recommends that the rates for the interruptible class be set using a value-of-service pricing approach. (See Sections 7.4.1 and 8.3.6)

Street Lighting Class

In its submission, NCPC proposed to treat street lighting on an incremental basis for cost allocation purposes. The Board finds this treatment unacceptable because it under-allocates costs to the street lighting class. The Board, therefore, recommends that NCPC treat street lighting like any other customer class for cost allocation purposes. (See Section 7.4.2)

Residential and Commercial Demands

In order to calculate the demands of the residential and commercial classes for cost allocation, NCPC used a formula which applied the load factor of the class to the kW.h sales plus losses of the class. In each rate zone, the load factors of the commercial class and residential class were assumed by NCPC to be equal to the system load factor plus one percent and the system load factor minus one percent, respectively.

NCPC's formula was the subject of much concern during the inquiry, with intervenors suggesting alternative approaches. After considering the evidence, the Board recommends that load factors of 45 and 55 percent be assumed for the residential and commercial classes respectively in all rate zones for the test year. The Board also recommends that NCPC thoroughly examine methods for determining demands of its residential and commercial classes in the future. (See Section 7.4.3.1)

Con Mine Demand

NCPC indicated during the inquiry that it meters Con Mine's (Con's) demand using an instantaneous demand meter and that the metered demands

formed the basis of the demand attributed to the mine in NCPC's cost allocation. NCPC explained that the nature of Con's operations makes the use of an instantaneous demand meter more appropriate. The Board also heard evidence from Cominco Ltd. (Cominco) concerning the use of the instantaneous demand meter. The Board finds that it is inequitable to base Con Mine's demand on an instantaneous demand meter when all of NCPC's other major customers are demand-metered on 15-minute intervals. The Board, therefore, recommends that, for cost allocation and rate design, NCPC base Con Mine's demand on a 15-minute interval. (See Section 7.4.3.3)

kW vs. kV.A

NCPC indicated during the inquiry that, in its submission, the demands of some of its customers were expressed in kWs, while the demands of others were expressed in kV.As. NCPC acknowledged, however, that it had used the two units of measurement interchangeably. The Board recommends that, in future submissions, NCPC use either kWs or kV.As, but not both, for cost allocation and that units of measurement be converted using power factors as appropriate to achieve the recommended uniformity . (See Section 7.4.3.4)

Line Losses

In its submission, NCPC did not distinguish between transmission line losses and distribution line losses and instead allocated all losses on the basis of the relative kW.h sales to each customer class. The Board notes that in effect NCPC's method allocates distribution line losses to industrial and wholesale customers even though these customers do not use distribution facilities. After considering various proposals made during the inquiry in this regard, the Board recommends that NCPC use a loss factor of 10 percent of sales to the residential, general service and street lighting classes to determine distribution losses attributable to those classes. (See Section 7.6)

Customer Weighting Factors

For the purpose of allocating customer-related costs to the various customer classes, NCPC weighted industrial (primary) and wholesale customers (with the exception of the "wholesale" customers in the NWT diesel rate zone) by a factor of 80. Many intervenors took exception to this weighting, arguing that it was too high. The Board, having examined the manner in which NCPC arrived at a factor of 80, finds the method to be inappropriate. The Board recommends that a weighting factor of 50 be used for industrial (primary) and wholesale customers in cost allocation. (See Section 7.7)

Customer-Specific Charges

In its submission, NCPC attempted to identify costs associated with facilities which serve only one customer or customer class. NCPC then assigned these costs only to the benefiting customer(s). However, when compiling its submission, NCPC also made the assumption that all transmission facilities within a rate zone are interconnected. Therefore, NCPC felt it would be contradictory to assign transmission or distribution facilities specifically to particular customers or customer classes. The Board notes, however, that the 138 kV transmission line from Whitehorse to Faro was built as a consequence of an agreement between the Government of Canada and Cyprus Anvil Mining Corporation (CAMC) to build a mining facility at Faro. The Board is doubtful that, in the absence of instructions from the federal government to do so, NCPC would have built the line in question. In the circumstances, the Board recommends that 85 percent of the costs associated with the line be assigned directly to Cyprus Anvil, and that the remaining 15 percent be assigned to all customers in the Yukon hydro rate zone, including Cyprus Anvil, on the basis of their relative demands. (See Section 7.3.4)

Residential Rates

NCPC's proposed residential rates in each rate zone consisted of a customer charge, declining block rates, and a minimum bill. The Board recommends that NCPC's residential rates consist of a fixed customer charge per month and a uniform energy charge. (See Section 8.3.2)

General Service Rates

In its submission, NCPC subdivided the commercial class into two groups for rate design purposes: a small general service group and a large general service group. NCPC designed differently structured rates for each group. The Board is not convinced that a distinction between the two groups is warranted for rate design and therefore recommends that in each rate zone one set of rates be designed for the commercial class as a whole. The Board further recommends that the rates take the form of a fixed customer charge per month, a flat demand charge per kW or kV.A of demand, and a uniform energy charge per kW.h of energy consumption. (See Section 8.3.3)

Fuel Adjustment Clauses and Thermal Generation Adjustment Clauses

The Board notes that the proposed rate schedules in NCPC's submission did not contain fuel adjustment or thermal generation adjustment clauses. Such clauses were formerly part of NCPC's rate schedules and were designed to protect NCPC and its customers from unanticipated changes in diesel fuel prices and, in the hydro zones, the amount of diesel fuel required. The Board is of the view that both types of clauses should be incorporated into NCPC's rate schedules for the test year. The Board further recommends that, in the future, NCPC give consideration to implementing a hydro rate stabilization fund for the hydro zones to eliminate the need for thermal generation rate adjustments. (See Sections 8.6 and 8.7)

Effect of the Board's Recommendations

The effect of the Board's recommendations is to reduce the consolidated revenue requirement by $11,756,000 from the $96,635,000 shown in the submission to $84,879,000. It would have been desirable to return the Board's recommendations to NCPC and to request the utility to submit rates that would conform with the recommendations for final Board approval. However, in this instance, because of the desire to complete the process in the shortest possible time, the Board calculated the rates to reflect all recommended adjustments and changes in rate structures. The resulting rates are shown in the tables at the end of Chapter 8.

Regulation of NCPC in the Future

The Board continues to believe that there is a need for an independent body to review and approve capital projects proposed by NCPC before construction is undertaken. The Board also continues to believe that NCPC's rates should be subject to review and approval by a regulatory agency, in a framework which allows input from interested parties. It is the Board's opinion that as long as responsibility for NCPC remains with the federal government, the Commission should be regulated by a duly-appointed federal regulatory agency. However, the Board is also of the view that in the event of NCPC's devolution to the territories or its privatization, the regulation of the utility operations should be carried out by the respective territorial public utilities boards.

Chapter 3
Rate Zones

By way of Order No. EHR-1-84, the Board required NCPC to file a rate design based on the recommendation set out in Section 4.4 of the Board's August 1983 report. The Board recommended that, in each of the territories, there should be two electric utility rate zones: a hydro rate zone and a diesel rate zone. In addition to these rate zones, NCPC's submission also contained a separate rate zone for the supply of electricity in Field, B.C. and separate rate zones in the NWT for NCPC's water & sewage service and for its heating service.

Prior to 1975, the NCPC Act required the Commission to review and establish rates for utility services annually on a plant-by-plant basis so that the revenue generated by those rates would be sufficient to offset projected expenses associated with each separate plant. In many remote communities, prior to NCPC taking over the supply of electricity, other government agencies had supplied local residents with this service in addition to supplying the agency itself. A system of government and nongovernment rates evolved which was continued by NCPC.

Amendments to the NCPC Act in 1975 permitted NCPC to establish rates for utility services on a rate zone basis rather than on a plant-by-plant basis. The NWT and Yukon were established as separate rate zones under the NCPC Act. While NCPC favoured the elimination of the multiplicity of rate schedules within Yukon and the Northwest Territories, it was of the view that this would be a lengthy process if major rate changes were to be avoided. While some progress has been made in simplifying rate schedules, the multiplicity of rates still persisted at the time of the inquiry.

In its submission to this inquiry, NCPC stated that it has no distinct preference for any specific rate zone proposal. However, the Commission did indicate that, at this stage of its development, it favours a rate design which is simple to administer and understand and believes that the use of a hydro rate zone and a diesel rate zone within each of the territories meets both criteria.

3.1 Yukon Rate Zones

Within Yukon, NCPC eliminated government rates in the late 1970's and, in 1979, NCPC announced its policy objective of achieving uniform rates by customer classification in all areas of supply over the next several years. NCPC stated that the objective was not achieved, however, as the result of concerns expressed by the Yukon Electrical Public Utilities Board. NCPC stated that as a consequence, when increases were necessary, NCPC continued to apply rate increases to hydro-serviced customers on an across-the-board basis, with the result being the continuation of the multiplicity of rate schedules.

As noted earlier, NCPC's submission was based on Yukon being divided into a hydro and a diesel rate zone.

As shown on Map 1, Dawson is the only community in NCPC's diesel rate zone.

The hydro rate zone is shown on Map 2 and consists of the Whitehorse-Aishihik-Faro system, the Mayo system and Johnson's Crossing. NCPC included Johnson's Crossing in the hydro rate zone even though it is currently served only by diesel generation. This was done because of NCPC's expectation that a transmission or distribution line would be constructed during the interim year from Whitehorse to Johnson's Crossing.

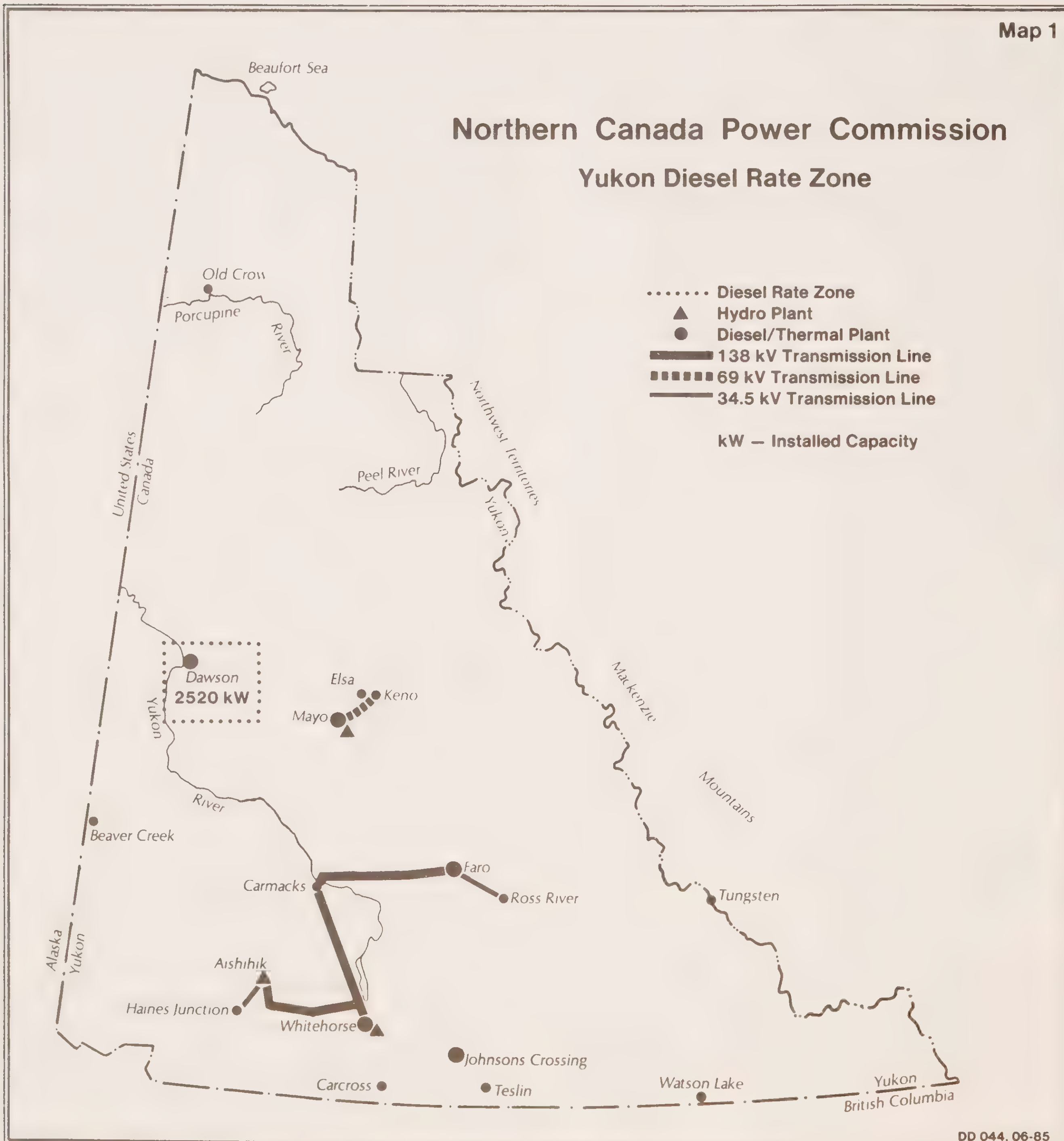
While most interested parties made no comment, some intervenors did express concern with the proposed rate zones.

The Government of Yukon (YTG) took the position that rate equalization in Yukon was desirable; that is, there should be only one rate zone comprised of both diesel and hydro areas.

On the other hand, United Keno Hill Mines expressed the opinion that Mayo should be treated as a separate hydro rate zone. In support of this position, UKHM emphasized that the Mayo plant is a totally separate system from the Whitehorse-Aishihik-Faro system. UKHM foresaw no benefit to it or the other

Mayo customers from being included with Whitehorse in one hydro rate zone. UKHM pointed out that its rates would increase by 170 percent and that this cost increase would result in a production cost increase of $2.13 per ounce of silver. Based on a price of silver of $6.20 per ounce, UKHM said that the proposed rate increase would put 200 jobs in jeopardy.

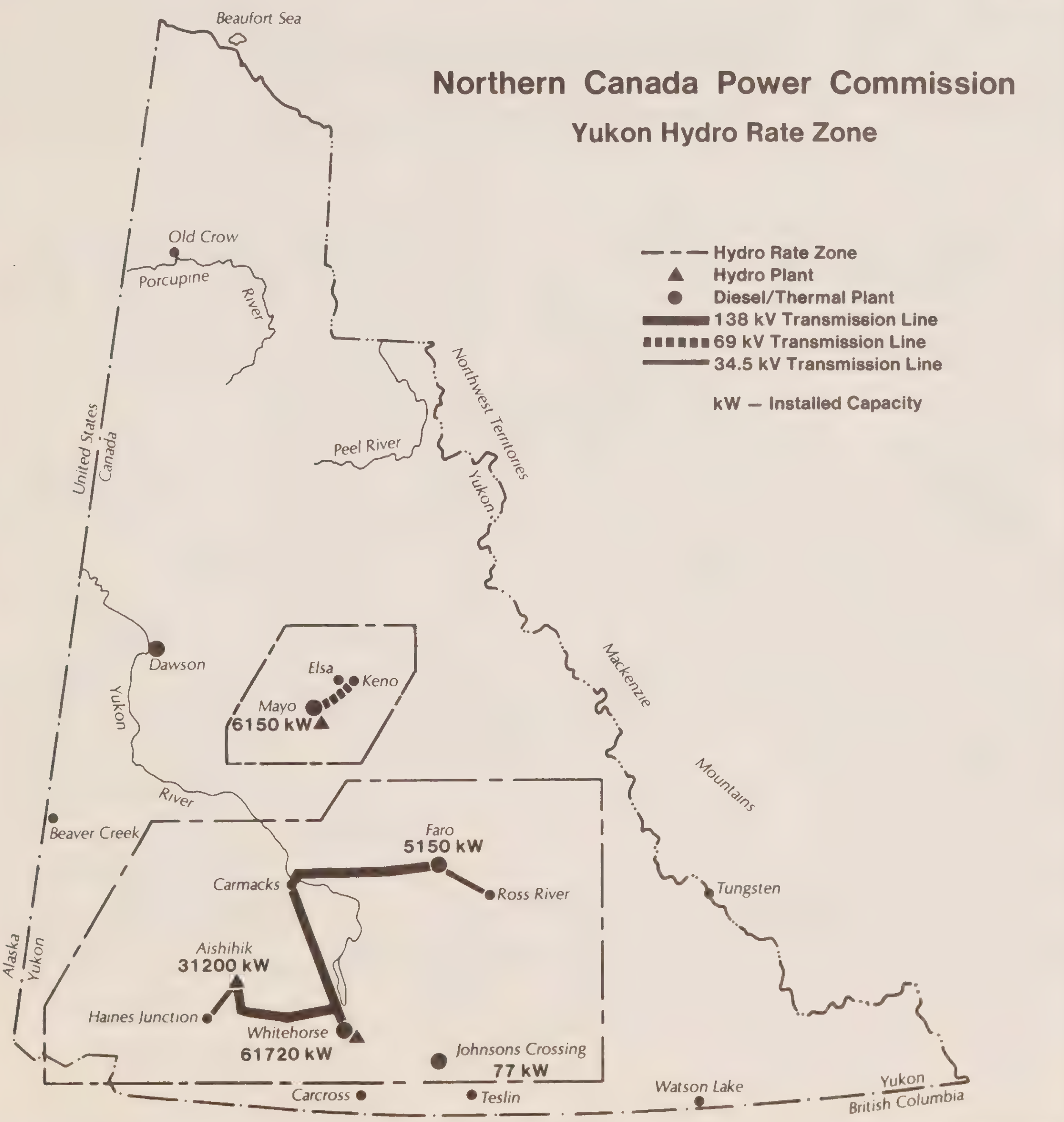
With regard to the inclusion of the Mayo and the Whitehorse-Aishihik-Faro systems in one hydro rate zone, the Board believes that as a general rule the grouping of more plants rather than fewer plants in a rate zone will contribute to rate stability. This occurs because the effects of low or high water years, maintenance expenditures or major capital additions on one system in a zone would be spread over a larger



customer base. The Board notes that, after giving effect to its recommendations, the Mayo customers might experience only modest savings in the test year if their rates were determined on a stand-alone basis; however, these savings could be negated as a result of NCPC's plans to rebuild the Mayo dam facility at an estimated cost of $6 to $10 million.

Having reviewed the evidence, the Board believes that plants with similar base load generation characteristics should be grouped together in the same rate zone. Therefore, the Board remains of the view that there should be one diesel and one hydro rate zone in Yukon.

Map 2



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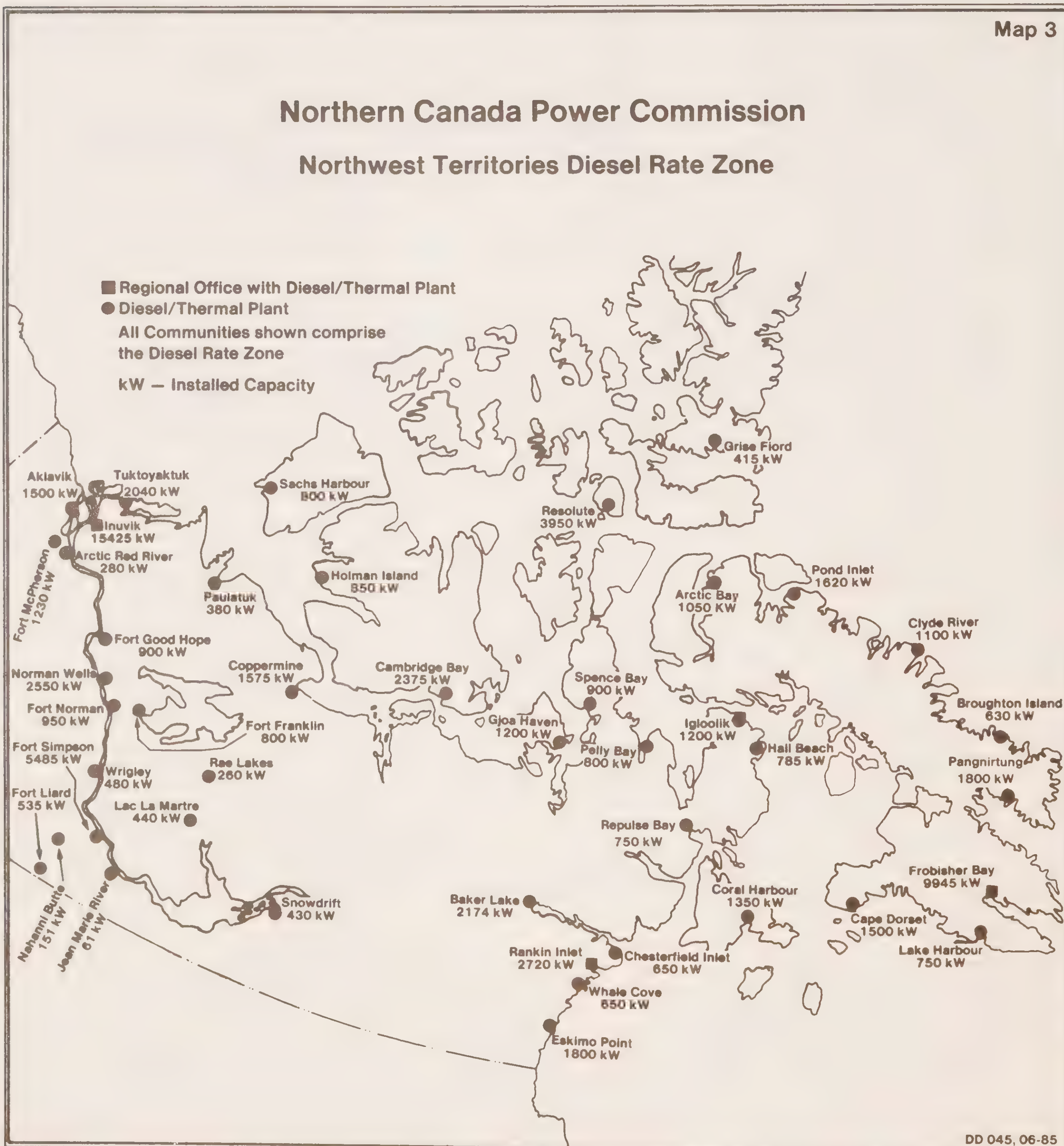
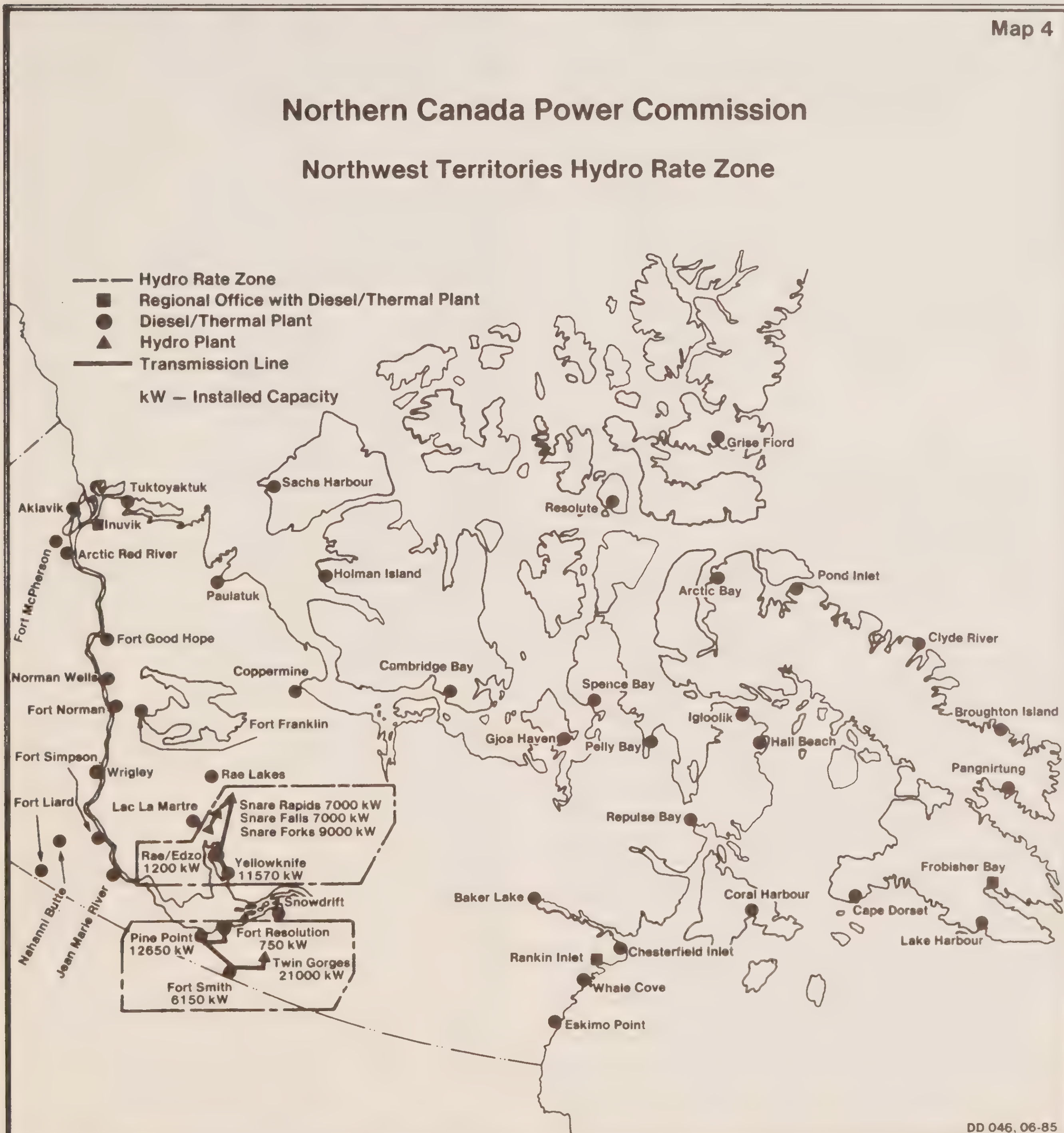
3.2 NWT Rate Zones

Because of the significant cost differences between the areas served and the preponderance of areas served by diesel generation, uniform rates by customer class have never been proposed by NCPC for implementation within the NWT. It was recognized that, whereas relatively small average rate increases would be necessary for hydro-serviced customers in Yukon to permit the implementation of uniform rates, rate increases would have to be much more severe in the NWT hydro-serviced areas to permit such a policy to be introduced. In recent years, a number of alternative proposals designed to rationalize utility rates within the NWT were examined and discussed with interested parties, including the Government of the Northwest Territories (GNWT) and the NWT Public Utilities Board, but no consensus was



reached regarding appropriate rate zones. In recent years, NCPC has attempted to reduce the disparity between government and nongovernment rates through the implementation of higher increases to nongovernment rates than to government rates as and when rate increases were found to be necessary. These piecemeal adjustments, together with the effect of Canada's Administered Prices Guidelines during the past two years, have resulted in the continuation of individual community rate schedules in the NWT.

As indicated earlier, NCPC's submission to this inquiry was based on the Northwest Territories being divided into a hydro rate zone and a diesel rate zone for electric utility service. In addition, the submission included a rate zone for heat service and one for water & sewage service.



Map 3 illustrates the geographically dispersed locations of the communities in the NWT diesel rate zone.

The location of the NWT hydro rate zone which consists of two systems, one north of and the other south of Great Slave Lake, is shown on Map 4.

Both Cominco and GNWT stated that they supported the hydro and diesel rate zones as set out in the submission.

The Town of Inuvik took the position that there should be only one rate zone in the NWT which would include both the diesel and hydro areas. However, the Town went on to say that, in the event that the decision was made to adopt hydro and diesel rate zones, there should be more than one diesel rate zone in the NWT to give recognition to the great variation of fuel costs from community to community.

Having reviewed the evidence, the Board believes that plants with similar base load generation characteristics should be grouped together in the same rate zone. Therefore, the Board remains of the opinion that there should be one hydro rate zone in the NWT. With respect to diesel, the Board believes that, while the matter may warrant reconsideration at some future date, there is insufficient evidence to demonstrate the need for more than one diesel rate zone in the NWT at this time.

Chapter 4
Rate Base

4.1 Introduction

Tables 4-1 and 4-2 show, on a consolidated basis, a summary of NCPC's rate base as submitted, NEB recommended adjustments and the NEB recommended rate base.

The Board's recommendations regarding the adjustments to be made to plant in service, accumulated depreciation and allowance for working capital are explained in succeeding sections of this chapter and are summarized for each cost centre and rate zone in Section 4.13. The resulting adjustments are detailed in Appendix F.

Table 4-1

NCPC Consolidated Rate Base ($000)

	Per Submission	NEB Adjustments	NEB Recommended
Plant in Service[1]	307,676	(81,569)	226,107
Accumulated Depreciation[1]	(109,075)	11,592	(97,483)
Net Plant in Service[1]	**198,601**	**(69,977)**	**128,624**
Unamortized Balance of Deferred Credit	—	(5,269)	(5,269)
Allowance for Working Capital	17,639	1,078	18,717
Total Rate Base	**216,240**	**(74,168)**	**142,072**

1 Average of opening and closing balances.

Table 4-2

Rate Base Summary ($000)

Rate Zone/Cost Centre	Per Submission	NEB Adjustments	NEB Recommended
Head Office	2,112	227	2,339
Yukon Regional Office	52	7	59
NWT Regional Office	173	(93)	80
Yukon Hydro	108,439	(67,631)	40,808
Yukon Diesel	2,413	(32)	2,381
Field, B.C.	59	5	64
NWT Hydro	43,191	(245)	42,946
NWT Diesel	53,067	(5,420)	47,647
NWT Heat	6,555	(946)	5,609
NWT Water & Sewerage	179	(40)	139
Total Rate Base	**216,240**	**(74,168)**	**142,072**

4.2 Whitehorse No. 4

The Whitehorse-Aishihik-Faro power system comprises the hydroelectric plants at Whitehorse and Aishihik plus the diesel- fuelled generating plants at Whitehorse and Faro. These plants and the communities they serve are linked by transmission and distribution lines. In 1982, because of forecasted load increases, a decision was made to expand the existing three-unit 20 MW plant at Whitehorse by adding a 20 MW unit referred to as Whitehorse No. 4. During the inquiry, the prudence of the decision to build Whitehorse No. 4, the cost of the project, and whether it is now used and useful were raised as issues.

4.2.1 Background

As one of the steps leading up to the construction of Whitehorse No. 4, NCPC applied to the Yukon Water Board for a water license. The water license, issued in June 1976, was approved by the then Minister of Indian Affairs and Northern Development on the condition that NCPC install fish incubation boxes to protect the salmon in the Yukon River.

NCPC did not proceed immediately with the construction of the fourth unit. In August 1981, because of forecasted cost increases, NCPC was instructed to provide a submission to the Cabinet Committee on Social Development to justify the project. The Commission engaged the firm of R.L. Walker and Partners Ltd. to conduct an economic and financial evaluation of Whitehorse No. 4.

This evaluation used a load forecast made by Hildebrandt- Young and Associates Ltd. which predicted that the 1980/81 load of some 315 GW.h would grow to some 381 GW.h by 1982/83. However, as a result of responses received to letters sent out by NCPC at regular intervals to its major users, the 381 GW.h demand forecast was reduced to 346 GW.h for 1983/84 (referred to as the central demand scenario) to reflect the scheduled closure of Whitehorse Copper Mine. The economic and financial evaluation assumed the load in the post-1984 period would remain steady at 346 GW.h per annum.

Hildebrandt-Young and Associates had also prepared alternative higher and lower demand scenarios. Under the low load growth scenario, generation requirements on the Whitehorse-Aishihik-Faro system were projected to decline to 255 GW.h by 1990/91 implying a severe and persistent decline in economic activity. The Walker report recognized that, under this scenario, Whitehorse No. 4 would not be needed as the projected loads could be met using the then existing hydro resources of NCPC.

The Walker report concluded that, under the central demand scenario, approximately 64 GW.h of diesel generation would be displaced by the use of Whitehorse No. 4 and that, based on estimated oil prices, a displacement of even 20 to 30 GW.h of diesel generation per year would make the fourth unit financially viable.

In January 1982, R.L. Walker and Partners reassessed the economic implications of this project due to estimated increases in the project cost. The 1982 Walker report indicated that the project would be viable unless the diesel generation displaced fell below 28 GW.h per year. The 1981 and 1982 Walker reports assumed that the addition of a 15 MW gas turbine plant would be needed to meet the capacity demand in 1984/85 if Whitehorse No. 4 were not built. The estimated cost of such a plant was credited to the cost of Whitehorse No. 4 in the analysis.

The January 1981 estimate of the project cost was $41,379,000. Based on the Whitehorse No. 4 Project Advisory Board's recommendation to the NCPC Board of Directors, a contract was awarded on 15 March 1982 for the construction of the project, including a fish hatchery, at an estimated cost of $52,000,000. This revised estimate, with the addition of interest during construction, resulted in a total estimated project cost of $60,000,000. Construction was completed by the end of 1983, but due to some operational difficulties, the unit was not commissioned until October 1984. This unit was included in NCPC's test year plant in service at a cost of $61,344,000. The project was financed by loans from the Government of Canada, with the first payments of principal and interest due on 31 March 1985.

During the period when the economic feasibility of Whitehorse No. 4 was being studied, the energy consumption of Cyprus Anvil's modified mill increased from 100 GW.h per year in 1981 to 140 GW.h per year in early 1982. However, in late March 1982, shortly after the construction contracts for Whitehorse No. 4 were awarded, Cyprus Anvil announced a two-month summer shutdown. The mine remained closed until June 1983 when it resumed limited operations. This work was subsequently suspended in October 1984 and at the conclusion of the inquiry, CAMC remained closed consuming only a small quantity of electricity for some essential operations. It remains unclear as to when, if ever, the mine will resume operation.

The result is that the test year forecast load of 200.988 GW.h on the Whitehorse-Aishihik-Faro system in NCPC's submission can be satisfied completely by the hydro resources that existed prior to the commissioning of Whitehorse No. 4. NCPC stated that Whitehorse No. 4, being a more efficient unit than the other units at the plant, is currently used to provide base load generation on the system.

4.2.2 Summary of Evidence

YECL took the position that $20,000,000 representing the unexplained increase from the original cost estimate of $41,379,000 should be excluded from rate base. In addition, YECL contended that the entire capacity of Whitehorse No. 4 is excess to the requirements of the Whitehorse-Aishihik-Faro system at this time. Therefore, YECL stated that no costs related to Whitehorse No. 4 should be included in the test year rate base. A witness for YECL was of the view that, since Whitehorse No. 4 can contribute only 5 MW at the time of system peak, only 5/20 of the $41,379,000 should ultimately be included in rate base. Further, the witness suggested that the cost of Whitehorse No. 4 should only be included in rate base based on the amount of diesel generation displaced, subject to the above 5 MW maximum.

YECL suggested that the repayment of principal and the payment of interest to Canada be deferred until there is some use made of the capacity and that interest in the interim period should be forgiven. While the witness was of the view that an allowance for funds used during construction (AFUDC) should accumulate on the costs excluded from rate base, he did not believe that AFUDC should be allowed to accumulate indefinitely. Further, YECL was not sure whether the fair market value of the Whitehorse No. 4 asset, rather than actual costs, should be used when the unit is eventually included in rate base.

In final argument, YECL submitted that there are two main reasons why NCPC should not have built Whitehorse No. 4. Firstly, the consultant's economic analyses were defective in their use of a capacity credit to account for 15 megawatts of diesel generation capacity which did not have to be built. Secondly, NCPC should have stopped construction in its infancy upon learning that the Cyprus Anvil mine was faced with a temporary shutdown. Cyprus Anvil contended that, in view of the fact that its mill

closed just after the construction contracts were awarded and recognizing the importance of the mine's load in justifying the investment in Whitehorse No. 4, NCPC should have examined the possibility of cancelling the contracts. Therefore, CAMC argued that the decision to proceed with the project was imprudent and that the costs should be excluded from rate base.

CAMC suggested that, if it were deemed appropriate to include the capital costs of Whitehorse No. 4 in rate base, at least the costs of the fish hatchery and fish screens and monies spent for public awareness should not be included in rate base. Further, Cyprus Anvil's expert witness suggested that the rates should be set using a demand and generation forecast which assumes that CAMC is in full production. The witness was also of the view that, if Whitehorse No. 4 were to be excluded from rate base, AFUDC should not be allowed to accumulate indefinitely.

The Government of Yukon contended that the effect of including the capital cost of Whitehorse No. 4 in rate base is too severe and that the average power rate with CAMC's present level of consumption would be 9.3¢ per kW.h, compared to 6.6¢ per kW.h if CAMC were to resume full production.

YTG took the position that Whitehorse No. 4 was constructed in the expectation of increases in load growth principally related to the mining sector. However, this sector's load requirement has, in fact, diminished significantly. YTG asserted that the remaining customers should not have to bear the burden associated with excess capacity that was intended for the use of one or two major mines.

On the subject of cost overruns, an expert witness representing YTG stated that he had not heard any evidence that would suggest to him that the capital cost of Whitehorse No. 4 was grossly unreasonable in the sense that seems to apply when considering the prudence of expenditures, with the possible exception of costs incurred with respect to fish-related facilities. In final argument, YTG requested the Board to determine the prudence of the increase in costs of the fish hatchery from original cost estimates for fish incubation boxes resulting from the apparent involvement of the Department of Fisheries. YTG also requested the Board to determine how much of the cost increase for the Whitehorse No. 4 tail race and fish screen was imprudently incurred.

The expert witness representing YTG put forth a short-term and a long-term proposal in order to alleviate the severe short-term cost increases associated with the commissioning of Whitehorse No. 4. The witness' short-term proposal was that the Government of Canada should forgive interest costs and defer all repayments of principal associated with loans made to finance construction of Whitehorse No. 4 for a three-year period beginning with the interim year. At the same time, NCPC should defer recovery of depreciation associated with Whitehorse No. 4. For the long-term, the witness proposed that Canada and NCPC should negotiate a long-term financial arrangement based on the expected length of time required to reach full utilization of Whitehorse No. 4 (without reducing the utilization of the hydro facilities which existed prior to completion of Whitehorse No. 4). The witness stated that this arrangement would involve deferment of principal payments and deferment and accrual of interest charges at favourable rates until full utilization is achieved.

This witness did not agree with YECL's suggestion that only 5/20 of $41,379,000 should ultimately be included in rate base. YTG confirmed that NCPC testified before the Yukon Electrical Public Utilities Board, in 1981, that the economic analysis did not reflect any peak capacity benefit from Whitehorse No. 4, but reflected only energy benefits.

YTG also argued that the Whitehorse-Aishihik-Faro system includes some diesel capacity that is completely surplus to the system's needs in the test year, and that any cost impact on NCPC from this surplus capacity should be excluded from the test year revenue requirement.

Other intervenors also contended that Whitehorse No. 4 was built expressly to serve the CAMC load and that other customers in the Yukon hydro rate zone should not be burdened with the annual capital and operating costs associated with that unit.

NCPC reiterated that Whitehorse No. 4 serves two functions: it provides energy and it also provides full capacity in the summer. NCPC argued that exclusion of Whitehorse No. 4 from rate base would be incorrect because, under the low load projections, Whitehorse No. 4 is no more superfluous to the system than any other facility such as Aishihik or Whitehorse No. 2.

NCPC pointed out that the diesel units on the Whitehorse-Aishihik-Faro system, although not currently required, are used and useful as stand-by capacity in the event that the line from Aishihik to Whitehorse should fail or when any of the hydroelectric units are out of service.

NCPC argued that the evidence is clear that the decision to construct Whitehorse No. 4 was prudent based on the information available at the time of the decision, that the project was well managed and that

the costs, to the extent they were within the Commission's control, were prudently incurred. The Commission stated that the real issue, which was of paramount concern to many intervenors and to NCPC as well, was the surplus capacity in the Whitehorse-Aishihik-Faro system as a result of the construction of Whitehorse No. 4 combined with the significant reduction in CAMC's energy requirements. NCPC concluded that the Board must ultimately decide the issue of the appropriate rate base treatment of Whitehorse No. 4. However, NCPC stated that the decision cannot be arrived at in isolation from a consideration of the issue of debt write-off, because NCPC is bound by its Act to recover in its rates the principal and interest related to loans outstanding whether or not the loans represent assets in rate base.

4.2.3 Prudence of the Decision to Build Whitehorse No. 4

The Board has examined the evidence regarding the justification to proceed with Whitehorse No. 4. The Board notes that there were flaws in the analysis which resulted in an overstatement of the benefits, but that even if corrections had been made at the time, the project would still have been found to be economic for the load scenario adopted.

Regarding the analysis, the Board notes that, although flow records for the Aishihik watershed had been kept since 1950, there appeared to be uncertainty, even in 1981, about the average annual energy output expected from the Aishihik plant. The R.L. Walker and Partners report used 90 GW.h as the annual Aishihik energy output, while the firm output expected when the plant was approved was 120 GW.h and the average annual output is now stated by NCPC to be 105 GW.h. The present stated hydro generation capacity under average flows in the system is 368 GW.h per year made up of 98 GW.h from Whitehorse No. 4, 165 GW.h from Whitehorse Nos. 1, 2 and 3 and the balance of 105 GW.h from Aishihik. If this latest information is accepted as correct, the amount of diesel generation to be displaced was overstated in the analysis by 15 GW.h per year, and the generation capability on the Whitehorse-Aishihik-Faro system, without Whitehorse No. 4, is now 270 GW.h.

The R.L. Walker and Partners analysis also assumed that a 15 MW gas turbine would be needed if Whitehorse No. 4 were not built and, in the Board's view, inappropriately allocated to the proposed new hydro plant a capacity credit, equivalent to the cost of this 15 MW gas turbine.

At the time of this analysis, 255 GW.h was the assumed generation capacity of Aishihik and Whitehorse Nos. 1, 2 and 3 under average flow conditions. R.L. Walker and Partners noted that, under the low load scenario of 255 GW.h, Whitehorse No. 4 would not be required as it would not displace any diesel generation.

The 1982 Walker report concluded that if 28 GW.h per year of diesel generation were displaced by Whitehorse No. 4, the project could be economically justified. The Board, based on its analysis which assumed an average annual output of 105 GW.h for Aishihik rather than 90 GW.h, has determined that the break-even point for the financial viability of the project would have required about 35 GW.h of diesel generation savings. This equates to a minimum generation requirement of 305 GW.h (270 GW.h plus 35 GW.h).

The Board notes that, in considering the decision to proceed with Whitehorse No. 4, no rate projections appear to have been made to show the increased rates which would result and that no elasticity studies were made to assess the possible effect of rate increases on demand. The assumption appears to have been that, since the annual costs associated with Whitehorse No. 4 would be less than the annual cost of providing the additional generation from diesel units, the effect on rates would be acceptable.

The Board notes the intervenors' arguments that consideration could have been given to cancellation or deferral of Whitehorse No. 4 when CAMC announced the summer closure of its mine and also notes CAMC's comments during the inquiry that it was still hopeful that the mine would reopen.

The Whitehorse No. 4 situation illustrates clearly the risks inherent in developing hydroelectric plants North of 60° to meet mining loads. However, considering the information that was available at the time the decision was made, the Board has concluded that there are insufficient grounds to say that the decision to build Whitehorse No. 4 was imprudent.

4.2.4 Cost of Whitehorse No. 4

The Board, having reviewed the evidence, concurs with NCPC that the costs, to the extent they were within the Commission's control, were prudently incurred. However, it is clear that some portion of the design changes and capital cost increases were attributable to the hatchery and other fish-related requirements imposed on NCPC.

The Board notes that the Department of Fisheries on more than one occasion altered the design criteria of the salmon enhancement facility from fish incubation boxes, which were estimated to cost $22,370 in 1975 to a fish hatchery which cost approximately

$1,000,000 to complete. Similarly, the Department of Fisheries required NCPC to modify the design of the tail race and the location of the fish screens. These modifications were estimated by NCPC to add an additional $850,000 to the capital cost of the project.

With respect to the fish hatchery, the Board is of the view that this facility changed markedly from the initial concept and that the present facility is designed to enhance the salmon population in the Yukon River rather than maintain the fish population at current levels. The Board has concluded that the requirement of the fish hatchery was not due to the construction of Whitehorse No. 4 and therefore recommends that $1,000,000 be excluded from the capital cost of Whitehorse No. 4 for rate-making purposes.

Regarding the fish screen modifications, the Board recognizes it is normal to include environmental-related costs as part of the total cost of hydro projects. The Board is, however, of the view that the cost of such modifications, in an area already faced with power rates substantially above those in most regions in southern Canada, should not be borne by the ratepayer. Therefore, the Board recommends that an additional $850,000 be excluded from the capital cost of Whitehorse No. 4.

4.2.4.1 Loan Returned to Government of Canada

NCPC indicated in its submission that, when the final bills were tallied, Whitehorse No. 4 was expected to cost approximately $61,344,000 and that this sum was borrowed from the Government of Canada to cover this cost.

Subsequent to the conclusion of the inquiry, NCPC informed the Board that the Commission had returned $975,000 to the Government of Canada because this amount was not required. Because this is apparently due to an expected reduction in the capital costs of Whitehorse No. 4, the Board recommends that the test year capital cost of Whitehorse No. 4 be reduced by a further $975,000.

4.2.5 Treatment of Whitehorse No. 4 for Rate-making Purposes

The Board finds that the hydraulic generation capability of the system under average flows without Whitehorse No. 4 would be 270 GW.h per year. Under the current forecasts for the test year and beyond, loads in the Whitehorse-Aishihik-Faro system could be met without Whitehorse No. 4. The question of how to deal with this situation, in which a $60,000,000 investment has been made based on a decision which appeared reasonable at the time, but which, due to changed circumstances, was not required at the in-service date, is dealt with in this section.

The Board notes that Whitehorse No. 4 is the most efficient of the four units at the Whitehorse Rapids plant and that NCPC is currently using it for base load generation on the Whitehorse-Aishihik-Faro system. Accordingly, the Board recommends that NCPC include in its test year revenue requirement the full amount of depreciation associated with the recommended capital cost of Whitehorse No. 4.

However, the Board questions whether construction should have proceeded given that CAMC announced the forthcoming summer closure of its mine shortly after the awarding of the contracts. While it is recognized that the Whitehorse No. 4 assets were financed by debt capital, the lender was, in effect, the owner who had ultimate control of the decision as to whether the project should proceed. Further, the Board notes that the facility is not required to meet NCPC's test year load projection on the Whitehorse-Aishihik-Faro system. The Board recommends that the test year net plant in service of Whitehorse No. 4 not be included in rate base, and not earn a return. The effect of this recommendation on loan repayments to the Government of Canada is dealt with in Section 5.2. The Board recommends that the assets removed from rate base be referred to as "assets specially classified".

The Board further recommends that, for rate-making purposes, NCPC commence in the test year to track separately in its books of accounts the capital cost of Whitehorse No. 4 and the associated accumulated depreciation so that these assets can be readily identified in any future submission.

The Board appreciates, however, that the loads of the Whitehorse-Aishihik-Faro system may recover in the future to the point where Whitehorse No. 4 will in fact be displacing diesel generation and will be meeting the purposes for which it was built. In this case, the Board believes that it would be appropriate to allow NCPC to phase into the Yukon hydro rate zone rate base the undepreciated capital cost of Whitehorse No. 4 to the extent that the facility is required.

As outlined in Section 4.2.3, any generation above 270 GW.h per year implies the need for Whitehorse No. 4. Therefore, the Board recommends that Whitehorse No. 4 be phased into rate base, if the forecast hydro generation is greater than 270 GW.h, using the following formula.

Rate Base
Component of Whitehorse No. 4 = NPIS x (FAHG - 270 GW.h)/35 GW.h

NPIS	net plant in service of Whitehorse No. 4 for a test year.
FAHG	forecast annual hydro generation on the Whitehorse-Aishihik-Faro system for that test year.
270 GW.h	the annual generation capability of Aishihik and Whitehorse Nos. 1, 2 and 3 under average flows.
35 GW.h	the minimum diesel generation that would have to be displaced to make the Whitehorse No. 4 unit financially viable.

The preceding formula allows the undepreciated capital cost of Whitehorse No. 4 to be included in rate base in proportion to its deemed contribution in a given test year up to a maximum equal to the then undepreciated capital cost associated with Whitehorse No. 4. The formula therefore allows NCPC a return, as determined in Section 5.2, on that portion of Whitehorse No. 4 included in the Yukon hydro rate base. For the test year, this portion is zero.

The Board recognizes that, given the current economic conditions in the Yukon hydro rate zone, the above formula may not allow any of the capital cost of Whitehorse No. 4 into rate base, and hence any of the related return into revenue requirement, for the next several years.

4.3 Aishihik Power Development

4.3.1 Background

The Aishihik hydroelectric facility is located 144 kilometres northwest of Whitehorse in the Aishihik basin and is interconnected to NCPC's Whitehorse facilities via a 138 kV transmission line. The major portion of this facility, including the dams, was constructed during the period 1973 to 1976. When the first contracts for construction of Aishihik were awarded by NCPC in 1973, costs were estimated to be $16,750,000 (excluding the transmission line). Evidence filed during the inquiry showed that, at the completion of the project, actual costs incurred amounted to approximately $39,290,000 (also excluding the transmission line).

4.3.2 Summary of Evidence

Two reports dealing with cost overruns on the Aishihik project were filed during the inquiry. The first, entitled "Hydro-Electric Development, Aishihik, Yukon and Strutt Lake, NWT" by R.N. Dalby and Associates Ltd., April 1976 (referred to hereinafter as the Dalby report), had been prepared at the request of the then Minister of Indian Affairs and Northern Development. The second document, called the "Report on the Review of the Aishihik Project" by Harold L. Johnston, P. Eng., and Ronald Ewoniak, C.A., October 1976 (referred to hereinafter as the Johnston/Ewoniak report), was commissioned as a result of the Dalby report's recommendation that an independent accountant and consulting engineer be retained to examine the Aishihik contracts.

While the intervenors noted that the prudence of the decision to build the Aishihik power plant was outside the scope of this inquiry, they did express considerable concern over the cost overrun of the project totalling some $22,500,000 and were of the view that some or all of the overrun was imprudently incurred and that the Yukon hydro rate base should be reduced accordingly.

In its final argument, CAMC remarked that NCPC had not, during the inquiry, objected to the findings of the Dalby or Johnston/Ewoniak reports, both of which were critical of the way NCPC managed the project. CAMC was also of the view that NCPC did not adequately justify the inclusion in rate base of the full cost of Aishihik. CAMC, therefore, proposed that the full amount of the cost overrun on the Aishihik project, after adjusting for accumulated depreciation, be disallowed from rate base.

The Government of Yukon, in final argument, recommended that $15,000,000 of the Aishihik construction costs be considered imprudent, and that depreciation and interest thereon be excluded from the revenue requirement.

A witness for YECL believed that the Dalby report constituted prima facie evidence of imprudence on NCPC's part. In his direct evidence, he proposed that $15,000,000 be removed from the Yukon hydro rate zone rate base in respect of Aishihik to ensure that the zone's customers are not further disadvantaged by NCPC's imprudence. In view of information provided later in the inquiry in the form of the Johnston/Ewoniak report, the witness revised his figure to $20,000,000, describing the whole document as a litany of imprudent management.

With regard to comments in the Johnston/Ewoniak report concerning the lack of cost controls, the lack of adequate formal reporting procedures, the lack of authorizations on certain force accounts and the fact that certain force accounts would normally be covered by the general contract, NCPC acknowledged that the comments in the report could be construed as criticisms of NCPC in carrying out the project.

4.3.3 Prudence of Cost Overruns

The Board believes that some of the overexpenditure with respect to the Aishihik project was the result of imprudent actions on the part of NCPC.

However, the Board notes that, during the construction period, the construction industry experienced unusual escalation of costs in general. Further, the Dalby and Johnston/Ewoniak reports indicated that, in hindsight, the original estimate of the cost of the project was too low.

The Board notes that neither of the reports was able to identify an amount by which the original estimate was too low nor were they able to quantify the proportion of the cost overrun attributable to unforeseen inflation during the construction period.

Under these circumstances, it is not possible for the Board to identify with precision an amount of expenditure which can be considered imprudent. However, based on the evidence and the comments in the Johnston/Ewoniak report regarding the lack of cost controls, the Board is of the opinion that a substantial amount should be eliminated from the original cost of Aishihik for rate base purposes. Accordingly, the Board is of the view that it would be reasonable to remove $12,000,000 from the original cost of the plant. The Board, after giving effect to accumulated depreciation recorded on this amount, recommends a net downward adjustment to the Yukon hydro rate zone test year rate base of $10,246,157.

4.4 Restatement of Accumulated Depreciation Using the Straight-line Method

The Board required NCPC to restate, in its submission, its accumulated depreciation using the straight-line method of depreciation as was recommended by the Board in its August 1983 report. NCPC had previously used a sinking fund method to depreciate assets placed in service prior to 31 March 1977 and a straight-line method for assets placed in service thereafter.

One intervenor suggested that NCPC use a sinking fund or annuity method of depreciation to determine the appropriate annual charges for depreciation, particularly in the hydro rate zones, but recognized that the straight-line method was used by most regulated utilities. Other intervenors were of the view that the straight-line method was more appropriate for NCPC.

The Board notes that the sinking fund method has the effect of deferring depreciation in the early years when interest costs are higher and charging it in later years when the interest costs would be lower (due to debt being paid off). However, since many hydro projects in the North are built originally to serve mining loads, which have limited expected lives, the effect is that the mining load could disappear before any substantial part of the plant has been depreciated and the remaining customers would be left to bear most of the depreciation charges for the plant.

Accordingly, the Board considers that using the straight-line method of depreciation will result in a more equitable distribution of capital costs over the life of the project and therefore recommends that NCPC be instructed to use the straight-line method of depreciation for all assets. The Board recognizes that the restatement of accumulated depreciation results in an under-recovery of depreciation as at 31 March 1984 of $35,650,000. The recommended treatment of this amount is discussed in Section 5.3.4.

4.5 Asset Lives of Plant in Service

In its submission, NCPC adopted asset lives based on the results of NCPC's in-house depreciation study. The Board's recommendations regarding the asset lives used by NCPC in its submission for hydro and diesel production plants are presented in the following sections.

4.5.1 Hydro Production Plants

NCPC has assumed asset lives of 30 to 50 years for its hydroelectric plants.

A witness for CAMC presented evidence showing that other publicly owned Canadian utilities, with the exception of Hydro-Québec, all use service lives ranging from 50 to 100 years for their hydro plants. This witness examined the estimated service lives of 68 Ontario Hydro hydroelectric stations and noted that all but two plants have asset lives in excess of 70 years.In final argument, CAMC took the position that until NCPC performs a definitive asset-life study, the Board should recommend that a life of 65 years be ascribed to NCPC's hydroelectric facilities.

A witness for NCPC suggested that asset lives of 50 to 100 years might be appropriate for NCPC's concrete dams. However, he believed an asset life of 40 years would be more reasonable for the dam at Mayo which is a wood crib structure.

The Board, being persuaded by the evidence, recommends that, until better information is available, NCPC use asset lives of 65 years for its hydro plants excepting the plant at Mayo. The asset life of that plant should remain at 40 years.

4.5.2 Diesel Production Plants

NCPC, in its submission, assumed asset lives of 10 and 15 years respectively for its small and large diesel units.

YECL testified that it uses a 25-year asset life for all of its diesel production plant based upon the results of its depreciation study. An expert witness for another intervenor stated that the asset lives of diesel units should not be set at more than 20 years and that a depreciation study should be conducted by an independent party to determine appropriate plant lives.

The Board acknowledges that the physical lives of these facilities may very well exceed the 10 and 15 years used by NCPC. However, the economic lives of these assets may be considerably shorter than 20 to 25 years as a result of more fuel efficient units being brought into production in the future. Therefore, the Board recommends that the asset lives assumed by NCPC for its small and large diesel units be accepted for the test year.

4.5.3 Depreciation Study

In its August 1983 report, the Board recommended that NCPC undertake a depreciation study to determine the physical and economic lives of its assets, and that NCPC calculate its depreciation expense for all of its assets on a straight-line basis over the shorter of the physical or economic life of the assets.

The Board notes that a number of intervenors in this inquiry also recommended that such a study be undertaken by NCPC or an independent party.

The Board is still of the view that such a study should be conducted in order to determine appropriate asset lives for NCPC's plant including its hydro and diesel generating facilities. The Board further recommends that such a study be undertaken by an independent party with expertise in this area.

4.6 Gifted Assets

NCPC included plant classified as "Gifted Assets" with a net book value of $12,189,000 in the test year rate base. Gifted assets are comprised of:

1. plant assets which NCPC has taken over at nil cost from various federal and territorial government agencies and has continued to operate (plant assets taken over from the Crown);
2. contributions in aid of construction from customers; and
3. insurance recoveries resulting from claims on destroyed plant.

During cross-examination, NCPC indicated that no attempt had been made to track separately each of the three components of gifted assets.

4.6.1 Plant Assets Taken Over From the Crown

During cross-examination, NCPC testified that, although the assets taken over from the Crown were received at nil cost, NCPC assigned an appraised value to them at the time of the transfer. NCPC stated that these assets should be included in rate base at their appraised value because they represent an investment by Canada in NCPC. None of the intervenors disagreed with this approach.

The Board is of the view that these assets should be considered an equity investment by Canada in NCPC, and therefore recommends that they be included in the test year rate base at the net book value determined by NCPC. The Board also recommends that, in the future, NCPC track separately in its books of accounts the appraised value of the assets taken over from the Crown and the accumulated depreciation thereon.

4.6.2 Contributions in Aid of Construction

NCPC's policy directive indicates that where the total estimated cost is in excess of $1,000 for a domestic/residential service, or where the total estimated cost is in excess of $200 for each anticipated kW of demand in the case of commercial/general service, the customers are required to make capital contributions for all such excess amounts.

NCPC testified that plant for which NCPC received the contributions in aid of construction had been included in test year rate base.

One intervenor stated that these contributions should be segregated from rate base to avoid double-charging the customers: once at the time of construction, and again in the future through the rates.

NCPC did not disagree with this treatment. However, when asked to provide a breakdown of gifted assets by type, NCPC indicated that it would have considerable difficulty in supplying the information and, in any event, would only be able to provide a corporate total for the accumulated depreciation associated with all the gifted assets.

The Board notes that normal utility practice dictates that contributions in aid of construction should be removed from rate base to avoid the double-charging of customers. The Board also notes that NCPC would have difficulty in identifying past contributions from its books of accounts. The Board therefore recommends that:

1. with respect to contributions in aid of construction made prior to the end of the test year, the

Commission's treatment for the test year be accepted;

2. NCPC identify, where possible, prior contributions in aid of construction and track these contributions separately by rate zone in its books of accounts. These contributions should be amortized at the same rate as the depreciation rate for that particular type of asset;
3. contributions in aid of construction made after the test year be tracked separately in the Commission's books of accounts and amortized at the same rate as the depreciation rate for that particular type of asset; and
4. the unamortized balance of contributions in aid of construction be deducted from rate base in any future submission.

4.6.3 Insurance Recoveries - Destroyed Assets

In its 1984 annual report, NCPC indicated that the 25-year old powerhouse at Inuvik, which serves the electricity, heat, and water & sewage services, was virtually destroyed by fire in 1983 and was subsequently rebuilt in the interim year.

In the base year, NCPC retired the assets destroyed by fire thereby reducing the original cost of plant in service by $1,875,000 and the accumulated depreciation by approximately $1,280,000. NCPC testified that the destroyed powerhouse at Inuvik had been replaced in the interim year at a cost of approximately $6,000,000 with this cost being fully covered by insurance proceeds.

However, NCPC indicated that during the interim year, it had included in "gifted assets" an amount of $7,793,000 for the reconstruction of the Inuvik plant, comprised of $6,000,000 of insurance recovery and $1,800,000 representing the net book value of the assets destroyed by fire.

The Board believes that NCPC's accounting treatment would be unfair to its customers for two reasons. First, the annual revenue requirement upon which the rates is based would include return and depreciation on assets previously retired. Second, the annual revenue requirement would include return and depreciation on assets that were not financed through debt or equity contributions but were paid for by insurance proceeds.

The Board notes that NCPC's accounting procedures are such that each asset, depreciation thereon, and retirement thereof, are accounted for on an individual basis.

Accounting for the retirement/replacement on an individual basis would yield the following:

1. The new assets replacing those destroyed by fire would be recorded on the books at a cost of $6,000,000 and the annual depreciation expense would reflect the original cost of the new assets ($6,000,000) and their estimated economic lives of 20 years.
2. A gain would be recognized on the retirement of the assets destroyed by fire and would be determined as follows:

Original Cost of Assets	$1,875,000
Less: Accumulated Depreciation	1,280,000
Net Book Value	$595,000
Insurance Proceeds	$6,000,000
Gain on Retirement: "Excess of Insurance Proceeds Over the Net Book Value of Assets Destroyed by Fire"	**$5,405,000**

In respect of this gain, the Board has apportioned it among the NWT diesel, heat, and water & sewerage rate zones as shown in Appendix F, Table F-28, and recommends that for rate-making purposes:

1. NCPC record the gain or "excess of insurance proceeds over the net book value of assets destroyed by fire" as a deferred credit in its books of accounts;
2. NCPC amortize the $5,405,000 deferred credit over a 20-year period, which is the same as the estimated asset life for the new Inuvik powerhouse;
3. NCPC deduct the unamortized balance in the deferred credit account from rate base;
4. the final costs of the new assets, when they become known to NCPC, be correctly reflected in its books of accounts; and
5. NCPC treat any future insurance recoveries in a manner similar to the Board's recommended treatment of the Inuvik powerhouse.

Accordingly, the Board as shown in Table 4-3 has reduced NCPC's consolidated rate base by $7,017,000 for the test year.

4.7 Transmission Line to Johnson's Crossing - Yukon Hydro Rate Zone

In its submission, NCPC included in plant additions for the interim year the cost of a single-phase transmission line which it proposed to construct from Whitehorse to Johnson's Crossing. The estimated cost of this line was $800,000.

During the inquiry, NCPC indicated that a final decision had not yet been made to build the line. Further, NCPC indicated that Treasury Board had not approved the borrowing of funds for this project. NCPC also testified that YECL has received approval from the Yukon Utilities Board to build a three-phase primary distribution line from Marsh Lake near Whitehorse to Teslin. This line, if constructed, would pass adjacent to the community of Johnson's Crossing.

Because there is considerable doubt that NCPC will construct its transmission line, the Board has removed the cost ($800,000) and associated accumulated depreciation ($13,000) of this facility from the test year rate base of the Yukon hydro rate zone. However, because it is possible that Johnson's Crossing may be interconnected to the hydro system by a distribution line built by YECL, the Board recommends that the $7,000 net book value of the plant at Johnson's Crossing remain in the Yukon hydro rate zone.

The test year rates which the Board recommends be charged to NCPC's customers at Johnson's Crossing are set out in Section 8.2.

4.8 Meters

In its submission, NCPC included in NWT regional office plant additions for the base year an amount of $100,000 for meters. During cross-examination, NCPC indicated that these meters were a holding inventory located in the meter shop at Yellowknife. NCPC also indicated that these meters could eventually be used in either territory. NCPC, therefore, agreed that for rate-making purposes the meters should be treated as part of the head office cost centre's rate base which would ensure their allocation to each rate zone.

The Board notes that these meters have been described as a holding inventory by NCPC and are not installed and in service. The Board, therefore, recommends that these meters be considered to be part of head office operating materials and supplies inventory rather than plant in service.

Table 4-3

Summary of Reduction in Rate Base Associated with the Inuvik Powerhouse Fire[1] ($000)

Reduction due to Assets Previously Retired	NWT Diesel Rate Zone	NWT Heat Rate Zone	NWT Water & Sewerage Rate Zone	Total
Plant in Service	1,524	255	14	1,793
Less: Accumulated Depreciation	38	6	1	45
Net Reduction	**1,486**	**249**	**13**	**1,748**
Reduction due to Unamortized Balance of Deferred Credit[2]	4,436	791	42	5,269
Total Reduction in Rate Base	**5,922**	**1,040**	**55**	**7,017**

1 For details of adjustments refer to Tables F-26, F-27 and F-28 in Appendix F.

2 Excess of insurance proceeds over the net book value of assets destroyed by fire amortized over a 20-year period.

4.9 Diesel Units Assigned to Incorrect Rate Zones

NCPC stated that, in its submission, it had incorrectly included in the NWT diesel rate zone a diesel generating unit which is physically located in Mayo, Yukon and similarly inadvertently included in the NWT hydro rate zone two generating units, one located at Clyde River, NWT and the other at Inuvik, NWT.

The Board recommends that the cost of these units and the associated accumulated depreciation be transferred to the appropriate rate zones.

4.10 Revision of Test Year Plant Additions

During cross-examination, NCPC indicated that its test year projection of plant additions should be reduced to reflect estimated cost reductions in the following projects:

1.	"Warehouse, garage and office facilities" at Dawson	$119,000
2.	"Safety, security and ground works" at Aishihik and Whitehorse	$183,000

The Board notes the testimony of NCPC and recommends that the test year plant additions be reduced accordingly.

4.11 Exclusion of 7.5 MW Power Plant re Pine Point Mines

NCPC indicated that it has a supply agreement with Pine Point Mines Limited (Pine Point Mines) that includes a payment schedule related to a 7.5 MW diesel plant installed by NCPC specifically for Pine Point Mines. The schedule specifies payments to be made by the mine in respect of principal and interest on NCPC's investment in the plant.

In light of this agreement, the Board recommends that for rate-making purposes the net book value of this plant be excluded from rate base in the NWT hydro rate zone and further that the associated interest cost be excluded from the determination of the weighted average cost of debt for the test year.

4.12 Allowance for Working Capital

4.12.1 Provision for Cash Working Capital

NCPC, in its submission, included a provision for cash working capital based upon an average 25.425 day lag in the timing of payments and receipts. The Commission amended this figure during the inquiry to 30.41 days. This calculation of the allowance was based on a refined lead-lag study, which incorporated improvements suggested by one intervenor for determining the average net receipt lag, and on a larger sample of revenue accounts.

During the inquiry, the Board noted that NCPC, in its refined study, had incorrectly determined the dollar-days for fuel expense. Using the correct figure in the determination of the weighted average expense lag days results in an average net lag of 31.59 days. The Board, therefore, recommends that the number of days used to determine the allowance for cash working capital in the test year be 31.59 days.

A number of intervenors suggested that separate lead-lag studies should have been carried out for each rate zone.

The Board is not persuaded that NCPC should perform separate lead-lag studies for each rate zone at this time, and therefore recommends that, for the test year, the allowance for cash working capital in each cost centre and rate zone be determined using 31.59 days.

4.12.2 Reduction of Fuel Inventory at Faro - Yukon Hydro Rate Zone

In estimating average fuel inventory for the test year, NCPC escalated the average of the base year opening and closing fuel inventories at each plant location by two percent in 1984/85 and by a further two percent for the test year to cover increased costs due to inflation.

NCPC submitted information that indicated that the opening and closing inventories at Faro in the base year were $246,236 and $97,917 respectively. NCPC indicated that the fuel inventory at Faro was reduced because of a decline in consumption of power by Cyprus Anvil. Given that the diesel fuel requirements at Faro are expected to remain at a low level for the test year, NCPC agreed that $97,917 would be a better estimate to use as the basis from which to derive the test year figure.

Accordingly, the Board recommends that the base year ending balance of fuel inventory be used as the basis for the test year inventory at Faro. The effect of this adjustment is to reduce the average test year inventory of the Yukon hydro rate zone by $77,000.

4.12.3 13-Month Average for Inventories

In its allowance for working capital, NCPC calculated operating materials and supplies inventory using a simple average of the opening and closing balances for the base year, increased by two percent for inflation in both the interim and test years. In the diesel rate zones, this inventory consists primarily of diesel fuel inventory.

NCPC stated that some of the Commission's diesel plants receive fuel on an ongoing basis throughout the year, while isolated communities receive fuel only once per year during the summer sea lift. The Board recommends that NCPC use, in the future, a 13-month average to determine average inventories in each cost centre and rate zone.

4.13 Summary of Adjustments to Rate Base

The Board's recommendations regarding the adjustments to be made to plant in service, accumulated depreciation, and allowance for working capital are set out below in this section for each cost centre and rate zone. The resulting adjustments to rate base are detailed in Appendix F.

Head Office Cost Centre

Allowance for Working Capital

1. Increase the operating materials and supplies inventory by $100,000 to reflect the transfer of meter inventory (Section 4.8).
2. Adjust net lag days of the cash working capital requirement calculation to 31.59 days from 25.425 days (Section 4.12.1).

Yukon Regional Office Cost Centre

Allowance for Working Capital

1. Adjust net lag days of the cash working capital requirement calculation to 31.59 days from 25.425 days (Section 4.12.1).

NWT Regional Office Cost Centre

Plant in Service

1. Reduce by $100,000 to reflect the transfer of meter inventory to the head office cost centre (Section 4.8).

Accumulated Depreciation

1. Reduce by $4,000 because NCPC had included the meter inventory in plant in service and recorded accumulated depreciation on these meters. This inventory has been transferred to the head office cost centre for rate-making purposes (Section 4.8).

Allowance for Working Capital

1. Adjust net lag days of the cash working capital requirement calculation to 31.59 days from 25.425 days (Section 4.12.1).

Yukon Hydro Rate Zone

Plant in Service

1. Reduce by $61,344,000 to reflect the removal of the cost of Whitehorse No. 4 (Section 4.2.5).
2. Reduce by $12,000,000 to reflect the disallowance of part of the capital costs of Aishihik (Section 4.3.3).
3. Reduce by $800,000 to reflect the removal of the cost of the proposed transmission line from Whitehorse to Johnson's Crossing (Section 4.7).
4. Increase by $285,000 to reflect the inclusion of the cost of the modular diesel unit at Mayo in the correct rate zone (Section 4.9).
5. Reduce by $183,000 to reflect the revised test year cost estimate of the "safety, security and ground works" project at Aishihik and Whitehorse (Section 4.10).

Accumulated Depreciation

1. Reduce by $994,000 to reflect the removal of the cost of Whitehorse No.4 (Section 4.2.5).
2. Reduce by $1,754,000 to reflect the disallowance of part of the capital costs of Aishihik (Section 4.3.3).
3. Reduce by $3,813,000 to reflect the use of a 65-year life for the depreciation of hydro production plants, excepting the plant at Mayo (Section 4.5.1).
4. Reduce by $13,000 to reflect the removal of the cost of the proposed transmission line from Whitehorse to Johnson's Crossing (Section 4.7).
5. Increase by $185,000 to reflect the inclusion of the cost of the modular diesel unit at Mayo in the correct rate zone (Section 4.9).

Allowance for Working Capital

1. Adjust net lag days of the cash working capital requirement calculation to 31.59 days from 25.425 days (Section 4.12.1).
2. Reduce the test year operating materials and supplies inventory by $77,000 to reflect the reduction of fuel inventory at Faro (Section 4.12.2).

Yukon Diesel Rate Zone

Plant in Service

1. Reduce by $119,000 to reflect the revised test year cost estimates of the "warehouse, garage and office facilities" project at Dawson (Section 4.10).

Allowance for Working Capital

1. Adjust net lag days of the cash working capital requirement calculation to 31.59 days from 25.425 days (Section 4.12.1).

NWT Hydro Rate Zone

Plant in Service

1. Reduce by $219,000 to reflect the inclusion of the costs of diesel generating units at Clyde River and Inuvik in the correct rate zone (Section 4.9).
2. Reduce by $5,380,000 related to the 7.5 MW diesel plant specifically assigned to Pine Point Mines Limited (Section 4.11).

Accumulated Depreciation

1. Reduce by $1,522,000 to reflect the use of a 65-year life for the depreciation of hydro production plants (Section 4.5.1).
2. Reduce by $219,000 to reflect the inclusion of the costs of diesel generating units at Clyde River and Inuvik in the correct rate zone (Section 4.9).
3. Reduce by $3,497,000 related to the 7.5 MW diesel plant specifically assigned to Pine Point Mines Limited (Section 4.11).

Allowance for Working Capital

1. Adjust net lag days of the cash working capital requirement calculation to 31.59 days from 25.425 days (Section 4.12.1).

NWT Diesel Rate Zone

Plant in Service

1. Reduce by $1,524,000 to reflect the treatment of the Inuvik powerhouse replacement (Section 4.6.3).
2. Increase by $219,000 to reflect the inclusion of the costs of the diesel generating units at Clyde River and Inuvik in the correct rate zone (Section 4.9).
3. Reduce by $285,000 to reflect the inclusion of the cost of the modular diesel unit at Mayo in the correct rate zone (Section 4.9).

Accumulated Depreciation

1. Reduce by $38,000 to reflect the treatment of the Inuvik powerhouse replacement (Section 4.6.3).

2. Increase by $219,000 to reflect the inclusion of the costs of the diesel generating units at Clyde River and Inuvik in the correct rate zone (Section 4.9).
3. Reduce by $185,000 to reflect the inclusion of the cost of the modular diesel unit at Mayo in the correct rate zone (Section 4.9).

Deferred Credit Balance

1. Set up an amount of $4,550,000 as a deferred credit to reflect the excess of insurance proceeds over the net book value of the Inuvik powerhouse assets destroyed by fire (Section 4.6.3).
2. Reduce by $228,000 to reflect the test year amortization of the deferred credit balance (Section 4.6.3).

Allowance for Working Capital

1. Adjust net lag days of the cash working capital requirement calculation to 31.59 days from 25.425 days (Section 4.12.1).

NWT Heat Rate Zone

Plant in Service

1. Reduce by $255,000 to reflect the treatment of the Inuvik powerhouse replacement (Section 4.6.3).

Accumulated Depreciation

1. Reduce by $6,000 to reflect the treatment of the Inuvik powerhouse replacement (Section 4.6.3).

Deferred Credit Balance

1. Set up an amount of $812,000 as a deferred credit to reflect the excess of insurance proceeds over the net book value of the Inuvik powerhouse assets destroyed by fire (Section 4.6.3).
2. Reduce by $41,000 to reflect the test year amortization of the deferred credit balance (Section 4.6.3).

Allowance for Working Capital

1. Adjust net lag days of the cash working capital requirement calculation to 31.59 days from 25.425 days (Section 4.12.1).

NWT Water & Sewerage Rate Zone

Plant in Service

1. Reduce by $14,000 to reflect the treatment of the Inuvik powerhouse replacement (Section 4.6.3).

Accumulated Depreciation

1. Reduce by $1,000 to reflect the treatment of the Inuvik powerhouse replacement (Section 4.6.3).

Deferred Credit Balance

1. Set up an amount of $43,000 as a deferred credit to reflect the excess of insurance proceeds over the net book value of the Inuvik powerhouse assets destroyed by fire (Section 4.6.3).
2. Reduce by $2,000 to reflect the test year amortization of the deferred credit balance (Section 4.6.3).

Allowance for Working Capital

1. Adjust net lag days of the cash working capital requirement calculation to 31.59 days from 25.425 days (Section 4.12.1).

Field, B.C. Rate Zone

Allowance for Working Capital

1. Adjust net lag days of the cash working capital requirement calculation to 31.59 days from 25.425 days (Section 4.12.1).

Chapter 5
Rate of Return

5.1 General

5.1.1 Submission

As outlined in Board Order No. EHR-1-84, the rate of return on rate base for the purpose of this inquiry was to be the cost of debt related to used and useful assets. In its submission, NCPC employed a corporate rate of return of 10.1984 percent in determining the return component of its revenue requirement for each cost centre and rate zone (see Appendix G). This rate included forecast new borrowings as at 31 March 1985 of $6,678,000 at an interest rate of 13 percent but excluded the Commission's $7,500,000 interest-free loan.

During the course of the proceedings, it was determined that the actual new borrowings would be $5,000,000 at an interest rate of 11.625 percent. In addition, subsequent to the conclusion of the evidentiary portion of the inquiry, NCPC prepaid principal on certain of its outstanding loans totalling approximately $5,329,000 (see Appendix G). These factors served to reduce the overall interest rate of NCPC's debt to a level of 10.1355 percent (see Appendix G).

5.1.2 Composite Interest Rate

As noted in Section 5.1.1, for the purpose of this inquiry, NCPC employed a corporate interest rate for debt in determining the return component of the revenue requirement for each cost centre and rate zone. In this regard, NCPC took the position that it would be a better approach to identify debt on a corporate basis rather than determining an interest rate for each individual rate zone and cost centre. During cross-examination, a witness for the Commission stated that there were several reasons why NCPC felt that the use of a composite interest rate for debt was more appropriate, noting that they were largely administrative in nature.

In final argument, NCPC noted that the use of a specific interest rate for each rate zone had been suggested during the course of the proceedings. However, the Commission argued that the various intervenors were generally supportive of the methodology employed by NCPC in its submission.

With respect to the use of a composite interest rate for debt, Cominco's evidence indicated that the methodology employed by NCPC appeared acceptable, suggesting that this practice is standard in the utility industry. The Board notes that ICG Utilities (Plains-Western) Ltd. (ICG) also supported the use of a composite interest rate for debt for NCPC.

Various intervenors took the position that NCPC's interest rate for debt should be calculated separately for each rate zone. In this regard, concerns were raised in connection with NCPC's proposed methodology because of the possibility of one customer group subsidizing another to the extent that interest costs were not allocated properly to each group. In support of this view, a witness representing GNWT noted the significant difference between the interest rates on debt associated with projects in each of the two territories.

The Board notes that there is some disagreement as to the use of a composite interest rate for NCPC. However, under the current circumstances, having regard to its past practices and the recommendations outlined in this report, the Board finds it appropriate to employ a composite interest rate for the purpose of establishing cost-based rates for NCPC in the test year.

5.1.3 Interest-free Loan

NCPC currently has an interest-free loan outstanding in the amount of $7,500,000. The Commission did not include this loan in the determination of its composite interest rate for the test year. In support of its composite interest rate calculation, a witness for NCPC stated that, while the overall interest rate of debt had not been reduced to reflect the interest-free loan, interest income forecast to be earned on the funds available because of this loan had been credited to NCPC's test year revenue requirement.

Cominco took the position that this loan was intended to cover working capital and, since working capi-

tal is a component of rate base, that this loan should be included in the determination of the Commission's overall interest rate. In final argument, Cominco further stated that the inclusion or exclusion of the working capital loan from the composite interest rate determination is an issue totally separate from the proper treatment that should be accorded interest income earned on investments.

In determining the appropriate interest rate for NCPC's debt, the Board is of the view that all debt related to the Commission's test year rate base should be considered. Therefore, having considered the evidence, the Board recommends that NCPC's interest-free loan of $7,500,000 be included in the determination of the Commission's overall interest rate.

5.2 Loans to be Deferred

As discussed in Section 4.2.5, the Board has recommended that the Whitehorse No. 4 facilities be excluded from NCPC's rate base for the test year. Accordingly, the loans outstanding associated with Whitehorse No. 4 have been excluded from the Board's determination of the Commission's test year composite interest rate (see Appendix H for details of the loans deferred).

In Section 4.2.5, the Board has recommended that depreciation related to Whitehorse No. 4 be included in the revenue requirement of the Yukon hydro rate zone. The Board further recommends that the revenue received as a result of this depreciation charge be used to repay outstanding principal associated with Whitehorse No. 4 related loans. Such payments should be made on all outstanding Whitehorse No. 4 loans in direct proportion to the outstanding balance of each of the loans. In addition, the Board recommends that the related loan agreements be amended so that the required principal repayments are equal to the depreciation charges for Whitehorse No. 4.

As previously noted, the Board has recommended the exclusion of Whitehorse No. 4 from test year rate base. Accordingly, no provision for return has been included in the test year revenue requirement with respect to the Whitehorse No. 4 facilities.

However, the Board has also recommended, in Section 4.2.5, that all or a part of Whitehorse No. 4 be phased into the Yukon hydro rate zone rate base at such time as Whitehorse No. 4 begins to be utilized to displace diesel generation. In determining NCPC's overall rate of return at that time, the Board recommends that an equivalent amount of loans outstanding, which relate to the Whitehorse No. 4 assets phased into rate base, be included in NCPC's capitalization at the composite interest rate of all outstanding Whitehorse No. 4 loans. The Board recommends that, in the meantime, the Whitehorse No. 4 loan agreements be amended such that no interest is payable on the loans until such time as the costs of these assets are phased into rate base.

5.3 Loans to be Forgiven and Written Off

NCPC's capitalization is primarily financed by debt, with monies received from the federal government by way of interest-bearing loans. In the current circumstances, NCPC's debt obligations include loans which are associated with assets no longer used and useful. As well, an evaluation of the assets presently in service indicates that, for the test year, the amount of NCPC's loans outstanding exceeds the net book value of the Commission's rate base. In this regard, the Board is of the view that it is appropriate, in determining cost-based rates for NCPC, for loans outstanding to equal rate base.

Normally, a firm's common shareholders would be the owners of the company. However, in this case, NCPC's debtholder (the federal government) is the owner of the Commission. The Board notes that numerous events take place in the operations of any company that are directly under the owners' control. In this regard, the Board considers that the present situation, whereby loans outstanding exceed rate base, is a result, to some extent, of past decisions made by the owner of the Commission. Since the Board is of the view that, in the case of NCPC, loans outstanding should equate to rate base, the Board considers it appropriate for the federal government to forgive sufficient of the outstanding loans to bring about this result. Accordingly, the Board recommends that loans totalling the difference between rate base and loans outstanding be forgiven by the federal government and that these loans be written off by NCPC. A detailed explanation relating to the forgiveness and writing off of specific loans is outlined in Sections 5.3.1 to 5.3.4.

5.3.1 Whitehorse No. 4

As discussed in Section 4.2.4, the Board has recommended that an amount of $1,850,000 relating to the fish hatchery and fish screen modifications be disallowed for inclusion in NCPC's rate base. Accordingly, the Board further recommends that principal outstanding on Whitehorse No. 4 related loans totalling $1,850,000 be forgiven by the Government of Canada and subsequently written off by NCPC. In this regard, the Board recommends that Loan No. B230-05 be partially forgiven and written

off. This loan was selected on the basis of its interest rate (13.75 percent), which most closely approximates the original composite interest rate of Whitehorse No. 4 debt (see Appendix I).

5.3.2 Aishihik

The Board, in Section 4.3.3, recommended that costs totalling $10,246,157 be disallowed from rate base with respect to cost overruns on Aishihik. The Board, therefore, recommends that loans totalling this amount be forgiven and written off. The Board notes that the pattern of loans associated with Aishihik appears to suggest that the overruns occurred in 1976, the year in which the majority of the Aishihik-related loans were issued. For the purpose of selecting specific loans to be forgiven and written off, the Board has chosen loans sequentially, beginning with the most recent loans made in 1976, on the basis that these loans would not have been incurred if no overruns had been experienced (see Appendix I for a summary of the loans recommended to be forgiven and written off).

5.3.3 Assets Not In Service

In its submission, NCPC identified loans, with an estimated outstanding principal of $13,085,000, relating to assets not in service. These loans were associated with assets no longer used and useful, interest during construction not previously capitalized and certain equipment that had not been entered into NCPC's production cycle.

Subsequent to the completion of the evidentiary phase of the inquiry, NCPC prepaid a portion of the outstanding loan balances related to these assets. After this prepayment, the estimated balance of loans outstanding, as at 31 March 1985, associated with assets not in service was approximately $9,266,000.

During the course of the inquiry, several intervenors voiced the opinion that loans associated with assets not in service should be written off. In this regard, one intervenor's witness stated that a write-off of these loans would be appropriate if the Board was to achieve its objective of establishing cost-based rates for NCPC. During cross-examination, a witness for the Commission stated that he subscribed to this view.

The Board is of the view that loans outstanding for NCPC should be related to assets actually in service. Having considered the evidence on this matter, the Board recommends that loans totalling $9,266,000 relating to assets not in service be forgiven and written off. For the purpose of establishing cost-based rates, the Board first selected loans for forgiveness and write-off on a plant-specific basis where possible. Where an asset not in service was traceable to a specific plant, the average interest rate of debt for that plant was calculated and loans were selected for forgiveness and write-off on the basis of proximity to that average. Loans to be forgiven and written off were selected in a similar manner for assets not in service that could only be traced to a specific cost centre or rate zone. Loans equaling any further assets not in service were selected for forgiveness and write-off based on the proximity of their interest rates to the residual overall interest rate of debt for NCPC (see Appendix I for a summary of the loans recommended to be forgiven and written off).

5.3.4 Under-recovery of Depreciation

As directed by the Board, NCPC restated accumulated depreciation in its submission using the straight-line method, as opposed to the previously employed methodology of a combination of straight-line and annuity depreciation techniques. As described in Section 4.4, the resultant under-recovery of depreciation brought about by this restatement equals $35,650,000. While the Board finds that it would be desirable to forgive and write off loans equal to the under-recovery of depreciation, the Board notes that the difference between loans outstanding (as revised to reflect previously discussed Board recommendations) and adjusted test year rate base is less than the stated amount of under-recovery of depreciation. Accordingly, in order to provide for the equation of loans outstanding to test year rate base, the Board recommends that the forgiveness and write-off of loans associated with the under-recovery of depreciation be limited to an amount equal to the remaining difference between loans outstanding and test year rate base.

In determining the loans to be forgiven and written off with respect to the under-recovery of depreciation, the Board notes that this under-recovery results from the restatement of depreciation using only the straight-line method. The Board is therefore of the view that the loans to be forgiven and written off should come from the group of outstanding annuity loans. In attempting to select specific loans for forgiveness and write-off, it was observed that one particular cost centre experienced an over-recovery of depreciation due to restatement. As well, certain rate zones which experienced an under-recovery of depreciation have rate bases which exceed loans outstanding. These factors prevented the Board from selecting loans identified by plant, cost centre or rate zone. Instead, the Board

first calculated the effective interest rate for all remaining annuity loans to be approximately 8.2 percent. Loans were then selected for forgiveness and write-off based on the proximity of their interest rate to this average and their order of appearance in the submission (see Appendix I for a summary of the loans recommended to be forgiven and written off).

5.4 Rate of Return on Rate Base

Having given consideration to the evidence presented and based on its findings, the Board is of the view that the appropriate rate of return on rate base for NCPC for the test year is 8.64 percent. This rate has been rounded upwards from the precise rate calculated by the Board (see Appendix J) in order to prevent NCPC from experiencing a shortfall as it relates to the recovery of interest expense.

Chapter 6
Revenue Requirement

6.1 Introduction

In order to design cost-based rates, NCPC calculated its costs of providing utility service, that is, its revenue requirement for the test year, using the rate base/rate of return methodology. The revenue requirement of each cost centre, namely the head office and two regional offices, and of each rate zone includes operating and maintenance expenses, depreciation expense and a return on rate base. The revenue requirement of each rate zone also includes its proportionate share of the head and regional office revenue requirements.

The Board's comments and recommendations regarding the various components of revenue requirement appear in succeeding sections of this chapter. Adjustments recommended by the Board to NCPC's revenue requirement on a consolidated basis are summarized in Table 6-1 and are shown for each rate zone in Table 6-2 and for each cost centre in Table 6-3. More detail is provided in Tables K-1 to K-10 in Appendix K.

Table 6-1

Consolidated Test Year Net Revenue Requirement
($ 000)

Particulars	Per Submission	NEB Adjustments[1]	NEB Recommended
COST OF SERVICE			
Operating Expenses			
Salaries and Wages	16,348	—	16,348
Fuel	29,583	8	29,591
Supplies and Services	16,779	(623)	16,156
Travel Expense	2,572	(78)	2,494
Total Operating Expenses	**65,282**	**(693)**	**64,589**
Depreciation Expense	12,326	(1,607)	10,719[2]
Amortization of Deferred Credit	—	(270)	(270)
TOTAL COST OF SERVICE	77,608	(2,570)	75,038
Less: Transfers Out	1,193	—	1,193
Interest Income	1,089	(589)	500
NET COST OF SERVICE	**75,326**	**(1,981)**	**73,345**
Return	22,052	(9,775)	12,277
TOTAL REVENUE REQUIREMENT	**97,378**	**(11,756)**	**85,622**
Less: Other Deductions	743	—	743
NET REVENUE REQUIREMENT	**96,635**	**(11,756)**	**84,879**

Table 6-2

Breakdown of the Consolidated Net Revenue Requirement by Rate Zone Inclusive of Head and Regional Office Allocations
($ 000)

	Per Submission	NEB Adjustments[1]	NEB Recommended
YUKON HYDRO RATE ZONE	19,950	(8,404)	11,546
YUKON DIESEL RATE ZONE	2,320	(15)	2,305
FIELD, B.C. RATE ZONE	346	3	349
NWT HYDRO RATE ZONE	16,004	(1,381)	14,623
NWT DIESEL RATE ZONE	50,232	(1,421)	48,811
NWT HEAT RATE ZONE	7,302	(464)	6,838
NWT WATER & SEWERAGE RATE ZONE	481	(74)	407
TOTAL	**96,635**	**(11,756)**	**84,879**

Table 6-3

Test Year Net Revenue Requirements of Cost Centres
($ 000)

	Per Submission	NEB Adjustments[1]	NEB Recommended
HEAD OFFICE	5,184	504	5,688
YUKON REGIONAL OFFICE	410	(3)	407
NWT REGIONAL OFFICE	206	(17)	189
TOTAL	**5,800**	**484**	**6,284**

6.2 Operating and Maintenance Expenses

6.2.1 General

The principal areas of operating and maintenance expenses examined during the inquiry were:

1. load and generation forecasts;
2. salaries and wages, including benefits;
3. fuel expense; and
4. other operating and maintenance expenses.

1 For explanations of NEB adjustments see the revenue requirement table for each cost centre and rate zone, Tables K-1 to K-10 in Appendix K.

2 Includes depreciation of $900,000 re Whitehorse No. 4 (see Table K-4 in Appendix K).

On a consolidated basis, NCPC projected its operating and maintenance expenses for the test year to be about $65,282,000, an increase of roughly 20 percent from the base year.

6.2.2 *Load and Generation Forecasts*

In its submission, NCPC's estimate of its operating and maintenance expenses was based on a load and generation forecast for the test year made in June 1984. During the inquiry, NCPC filed an updated load and generation forecast dated October 1984. The updated forecast revised several figures from the June 1984 forecast and in order for the rest of its submission to reflect the revised forecast, NCPC indicated that a considerable number of changes would have to be made to its three-volume submission.

While the Board is of the view that it would normally be desirable to use the most recent forecast to design rates, it did not believe that it would be appropriate in this case to require NCPC to revise virtually its entire submission for the test year. The Board, therefore, has used the June 1984 forecast included in the submission to determine the cost of service and cost-based rates in each rate zone for the test year.

6.2.3 *Salaries, Wages and Benefits*

The Commission, in its estimate of test year salaries and wages, provided for an increase of four percent over the interim year. NCPC stated that four percent was its best estimate of what could be achieved from the current wage negotiations. With regard to employee benefits, the Commission has indicated it has a basic benefit package which encompasses all employees and includes superannuation, supplementary death benefit insurances, group life insurance, Blue Cross, and territorial/provincial health care. In addition, the Commission also provides all employees North of 60° a location differential payment to cover a cost of living differential and environmental allowance. NCPC stated that the estimates of the location differential payment for the test year were based on the schedules of isolated post allowances issued by Treasury Board.

The Board finds NCPC's request for a four percent increase in salaries and wages to be reasonable in light of current wage settlements and general inflation rate trends. The Board also accepts NCPC's estimates of employee benefit costs for inclusion in the cost of service.

Intervenors expressed concern over the significant increases, compared to the base year, in salaries and wages assigned to the different functions in the various rate zones. The evidence shows that the increases were the result of refinements made by NCPC to its budgeting methods used to assign labour costs from parent plants to satellite plants and to each function within each rate zone. The Board is of the view that the refinements made by NCPC are reasonable.

6.2.4 *Fuel Expense*

In estimating its diesel fuel requirements for the test year, NCPC used its June 1984 generation forecast and estimates of fuel efficiency of individual plants. For the hydro rate zones, NCPC assumed normal water flows. In its calculation of the test year fuel expense, NCPC assumed a two percent increase in the price of diesel fuel over 1984/85 prices.

Included in its estimate of the test year fuel expense for the NWT diesel rate zone was an estimate of the cost to NCPC of purchasing power from Esso Resources Canada Limited at Norman Wells.

Except as outlined below, the Board accepts NCPC's test year estimate of fuel expense for each rate zone.

NCPC included Johnson's Crossing in the Yukon hydro rate zone reflecting the Commission's expectation of building a transmission line from Whitehorse to Johnson's Crossing during the interim year.

For the reasons outlined in Section 4.7, the Board is not convinced that NCPC will proceed with the construction of the transmission line to Johnson's Crossing. Because the Board believes that the possibility exists that Johnson's Crossing may be interconnected to the hydro system during the test year by a distribution line built by YECL, the Board has not removed from the Yukon hydro rate zone the expenses included in the submission for maintaining the facilities at Johnson's Crossing. However, the Board believes it is unlikely that any interconnection will take place before the middle of the test year. Therefore, the Board has deemed it appropriate to increase the fuel expense in the Yukon hydro rate zone by $7,650, which is the Board's estimate of diesel fuel expense at Johnson's Crossing for six months in the test year.

6.2.5 *Other Operating and Maintenance Expenses*

In its submission, NCPC's operating and maintenance expenses other than salaries and wages and fuel expense were grouped under the headings of supplies and services and travel expense for each rate zone. NCPC indicated that supplies and services

include materials and supplies, outside services, insurance, municipal taxes and other expenses.

Several intervenors expressed concern regarding the reasonableness of NCPC's projections of test year operating and maintenance expenses. However, they indicated that they were unable to draw a meaningful comparison of costs between the base and test years.

NCPC stated that its annual maintenance budget for each rate zone includes estimates for three cost elements: ongoing maintenance, such as annual inspections, preventative maintenance and scheduled maintenance; a provision for unanticipated maintenance; and specific requirements for the year such as cavitation repair, runner maintenance and transmission line brush cutting. NCPC indicated that the budget for a plant site can fluctuate significantly from one year to the next depending on whether a major overhaul of a diesel unit is scheduled to be performed during a year.

NCPC further stated that the base year actual expenses were not typical because the Commission, whose rates were subject to Canada's Administered Prices Guidelines, had implemented a number of cost-cutting measures that resulted in the deferral of many low priority programs. NCPC also stated that it had introduced annual inspection and maintenance programs, in the interim year, to improve system reliability.

The Board acknowledges that maintenance programs in any given year may not be comparable to those of a previous year with respect to scope of work and total cost. The Board notes that these circumstances limit the validity of judging the reasonableness of NCPC's test year operating and maintenance expense budget by comparing it to costs incurred in a previous year. However, the Board notes that in 1982/83 and 1983/84, NCPC's actual operating and maintenance expenses, excluding fuel and contingencies, were lower than the budget by 5.7 percent and 7.3 percent respectively. NCPC also indicated during the inquiry that it expected its 1984/85 actual operating and maintenance expenses, excluding fuel, to be about 3.5 percent below budget.

On the basis of an examination of NCPC's "actual to budget" results for the past three years, the Board finds it appropriate to reduce, for rate-making purposes, the operating and maintenance expenses (excluding salaries and wages, and fuel) as budgeted and presented by NCPC in its submission. For its calculation of NCPC's test year revenue requirement, the Board therefore has reduced the operating and maintenance expenses (excluding salaries and wages, and fuel) for each cost centre and rate zone by three percent.

In addition to this three percent adjustment, the Board finds it necessary to make an additional adjustment to supplies and services expense in the NWT hydro and NWT diesel rate zones. During cross-examination, NCPC stated that the amounts of $65,800 and $53,800 provided for the capital asset appraisal program in the NWT hydro and NWT diesel rate zones respectively would not be spent in the test year. The Board, therefore, recommends that these amounts be excluded from the test year cost of service for these rate zones.

The Board has taken into account the preceding adjustments in calculating the revenue requirement for each cost centre and rate zone.

6.2.6 Other Matters

6.2.6.1 Unscheduled Maintenance

On a consolidated basis, NCPC provided $2,000,000 for unscheduled maintenance in the test year cost of service and used the following formula to allocate this amount to each rate zone. Ten percent of this amount ($200,000) was assigned to the hydro rate zones and the remaining 90 percent ($1,800,000) was assigned to the diesel rate zones. The $200,000 assigned to the hydro rate zones was prorated between the Yukon hydro and NWT hydro rate zones on the basis of their respective generation forecasts for the test year. The $1,800,000 assigned to the diesel rate zones was prorated on a similar basis among the Yukon diesel, NWT diesel and the Field, B.C. rate zones. Within each rate zone, NCPC assigned the amount for unscheduled maintenance to the production function because unanticipated costs incurred for other facilities have been miniscule compared to those for generating facilities.

The Board notes that the extent of unanticipated maintenance may be closely related to the vintages of plant and equipment and the level of scheduled maintenance being carried out. NCPC's formula for assigning the amount for unscheduled maintenance to a rate zone does not consider the actual cost of unanticipated maintenance experienced in that zone. In fact, the results of the formula are more likely to reflect events occurring in other rate zones, such as increases or decreases in diesel generation. The evidence shows that using NCPC's method, the amount allocated to the Yukon diesel rate zone was $86,500 which was some 37 percent of that zone's total production maintenance expense of $230,000 and roughly 60 percent of the amount budgeted for

scheduled production maintenance for the zone. NCPC, when questioned whether it would be more appropriate to make separate estimates of unscheduled maintenance for each rate zone on the basis of historical data, replied that such estimates could be made.

It is the Board's view that in future NCPC should estimate the unscheduled maintenance expense for each rate zone on the basis of historical experience of such occurrences in the rate zone. However, due to the lack of the information necessary to use this approach for the test year, the Board has accepted the approach used by NCPC in its submission.

6.2.6.2 Capitalizing vs. Expensing

In its maintenance budget for the test year, NCPC made provision for several items such as pole replacements and renovations, retrofits and roof repairs of buildings. NCPC was questioned about the appropriateness of such expenditures being classified as expenses given that other utilities would capitalize some of these expenditures. For example, a witness for YECL stated that YECL would capitalize pole replacements as well as the installation of stubs and guy guards, but would expense renovations, retrofits and roof repairs of buildings.

The Board recommends that NCPC examine the capitalization and expensing policy of other utilities to determine if its capitalization policy should be revised.

Further, in cross-examination, NCPC indicated that there have been instances where an expenditure originally classified as an expense in the budget for rate-making was subsequently capitalized. NCPC agreed that, as a result, its customers would end up paying for the expenditure twice; once through the cost of service used to establish rates for the year, and subsequently through the depreciation expense charged in future years' rates.

The Board recommends that, in the future, NCPC not capitalize any costs that have already been budgeted as an expense in determining the revenue requirement used to set the rates for a given year.

6.3 Depreciation Expense

In its submission, NCPC included depreciation expense in the revenue requirement for each cost centre and rate zone based on assets expected to be in service during the test year. After giving effect to its recommendations in Chapter 4 regarding capitalized values for assets and the asset lives on which depreciation should be based, the Board has reduced the depreciation expense submitted by NCPC by $1,607,000 on a consolidated basis. The Board's adjustments to depreciation expense for each cost centre and rate zone are shown in Tables K-1 to K-10 in Appendix K.

6.4 Amortization of Deferred Credit

Based on its recommendation made in Section 4.6.3, the Board has determined the annual amortization amount in respect of the amortization of the deferred credit associated with the excess of insurance proceeds over the net book value of assets destroyed by fire at Inuvik, NWT to be $270,260.

The Board recommends that this amount be credited to the test year cost of service. Accordingly, the Board has adjusted the revenue requirements of the NWT diesel, NWT heat and NWT water & sewerage rate zones by appropriate amounts as set out in Tables K-8 to K-10 in Appendix K.

6.5 Return on Rate Base

NCPC included a return on rate base in the revenue requirement for each cost centre and rate zone. As a consequence of the recommendations in Chapters 4 and 5, the Board has reduced the return sought by NCPC by $9,775,000 on a consolidated basis. The Board's adjustments to return on rate base for each cost centre and rate zone are shown in Tables K-1 to K-10 in Appendix K.

6.6 Allocation of Head Office Revenue Requirement

In its submission, NCPC allocated the head office revenue requirement to rate zones in proportion to direct salaries and wages. This was a change from the method of allocation NCPC had been following since 1977. In the previous method, head office revenue requirement was allocated to service areas on the basis of demand (30%), energy (30%), number of customers (30%) and plants (10%).

Several intervenors criticized NCPC's proposed method of allocation. GNWT contended that the allocation of head office costs on the basis of salaries and wages was inappropriate because an excessive proportion of head office costs was allocated to the more labour-intensive diesel rate zones.

NCPC stated that there are several ways of distributing overhead costs, but that no one method best suits all types of costs. However, NCPC stated that salaries and wages provide a relatively stable base which can be measured. NCPC said that, following a consultant's recommendation, it analyzed the head office functions to identify costs which could be specifically assigned to specific areas prior to prorating

the remaining costs on the basis of salaries and wages, but found that specifically assignable costs were small in relation to the overall administrative effort that was required to identify them. Upon being asked to describe the causal relationship between several of the head office expenses and rate zone functions and to suggest appropriate bases for allocating such expenses, a witness for NCPC stated that NCPC had used this approach prior to 1976, but found it cumbersome and had looked for a more administratively acceptable methodology.

In final argument, GNWT and Cominco suggested that head office costs should be allocated on the basis of cost causation to the extent practical. GNWT suggested that the remainder of the costs should be allocated on a basis which spreads costs equitably, such as all other operating costs excluding fuel.

Cominco further suggested that head office costs should be identified by function, and that a thorough study should be undertaken in the future to determine exactly how those costs should be allocated. However, Cominco indicated that this information was not available at the time of the inquiry.

The Board recognizes that not all head office costs can reasonably be allocated to rate zones using a single allocation basis such as salaries and wages, or operating and maintenance expenses, excluding fuel. As a result, it is probably necessary to use more than one basis for allocating head office costs.

Therefore, the Board recommends that NCPC in the future identify by function its head office costs and determine an appropriate basis for allocating each functionalized cost to rate zones.

Because such information was not available for this inquiry, the Board was left with the necessity of using NCPC's method to allocate head office costs for the test year. However, the Board believes that this method is inappropriate for assigning interest income earned on temporary cash investments (see Section 6.6.1) and further that it results in unacceptable increases in head office costs allocated to the NWT heat and NWT water & sewerage rate zones (see Section 6.6.2).

6.6.1 Interest Income

NCPC, in determining its test year head office net revenue requirement, deducted from cost of service an amount of $1,089,000 related to interest income earned on temporary cash investments. The Commission used an interest rate of 10.25 percent in arriving at this amount.

The build-up of the temporary cash is due essentially to the fact that NCPC pays interest and principal on its outstanding debt obligations at the end of each fiscal year, while the revenue to cover these obligations is collected over the year. Given that the Board, in Section 5.3, has recommended that loans equate to rate base, the Board believes that it would be more appropriate to allocate interest income to the various rate zones in proportion to the rate base for each rate zone.

However, the Board is of the view that the interest income earned on temporary cash investments will probably be less than that forecast by NCPC in its submission. In this regard, the Board notes that the recommended overall return component of revenue requirement is approximately 55.7 percent[1] of the total return included in NCPC's submission. Giving consideration to the above, and assuming a short-term interest rate of 8.5 percent, the Board recommends that the amount of interest income be reduced to $500,000.

6.6.2 Allocation of Head Office Costs to the NWT Heat and Water & Sewerage Rate Zones

The Board recommends that the amounts allocated for the test year to the heat and water & sewerage rate zones be determined by escalating the amounts of head office costs allocated to these zones in the base year by the percentage increase in head office revenue requirement from the base to test year. The balance of the head office revenue requirement, exclusive of interest income, should then be allocated to electric utility rate zones using NCPC's proposed method. The Board has used this procedure to allocate the head office revenue requirement to each rate zone. The amounts allocated to the various zones are set out in Table K-1 in Appendix K.

6.7 Allocation of Regional Office Revenue Requirements

NCPC also allocated the revenue requirement of each regional office to the respective rate zones in each territory on the basis of salaries and wages. The Board's views on the allocation of regional office costs are similar to those addressed for head office costs. Accordingly, the Board recommends that, for the test year, the amounts of the NWT regional office costs allocated to the heat and water & sewerage rate zones should be determined by escalating the amounts allocated in the base year by the percent-

1 The recommended return of $12,277,000 divided by the per submission return of $22,052,000 (see Table 6-1).

age increase in the NWT regional office revenue requirement from the base to the test year. The balance of the revenue requirement should then be allocated to both electric utility rate zones in the NWT using NCPC's method. With respect to the allocation of the Yukon regional office revenue requirement, the Board recommends that NCPC's method be used for the test year. The revenue requirements of the Yukon and NWT regional offices and their allocation to the respective rate zones as recommended by the Board are shown in Tables K-2 and K-3 respectively.

6.8 Summary of Revenue Requirements By Rate Zone

For each rate zone, the net revenue requirement as shown in NCPC's submission and as recommended by the Board are provided in Tables K-4 to K-10 in Appendix K.

Chapter 7
Fully Distributed Cost of Service Study

7.1 Introduction

The Board, in its August 1983 report, recommended that NCPC design cost-based rates. To design cost-based rates for an electric utility it is necessary to perform a fully distributed cost of service study.

7.1.1 Fully Distributed Cost of Service Study

The purpose of a fully distributed cost of service study is to allocate the net revenue requirement of a rate zone to specific customers and to the various customer classes in the zone. The costs allocated in this manner are then used in the design of cost-based rates for each class. The cost of service study is based on the principle that all utility costs can be either directly assigned to specific customers or related to demand, energy and customer components.[1] The basic tasks to be performed in such a study consist of functionalizing, classifying and allocating costs.[1]

The general procedures followed by NCPC in developing its test year cost of service study as described in its submission are as follows:

1. Total operating costs (excluding allocated head and regional office costs) were compiled and the rate base was identified for each proposed rate zone, i.e., Yukon hydro, Yukon diesel, NWT hydro, NWT diesel and Field, B.C.
2. Head office and regional office administration revenue requirements were allocated to the rate zones and to the various electrical, heat and water & sewage utilities on the basis of forecast direct salaries and wages.
3. Costs and rate base associated with the nonelectric utilities (heat and water & sewage services) were either directly identified or allocated to the nonelectric utilities.
4. Estimates of street lighting costs and associated rate base were compiled and the costs were assigned directly to the street lighting customer classification in each rate zone.
5. After removal of nonelectric and street light related costs and rate base, all remaining electric utility costs and rate base, including the allocated head and regional office costs for a rate zone, were functionalized, where possible, into the following categories: production, transmission, distribution, support facilities, plant administration and general expenses, employee facilities, and depreciation.
6. The functionalized costs and rate base were then classified to demand, energy and customer components taking into consideration, insofar as practical, standard industry practices as outlined in the National Association of Regulatory Utility Commissioners (NARUC) "Electrical Utility Cost Allocation Manual" and the American Public Power Association (APPA) "Cost Allocation Manual" and the recommendations contained in the Price Waterhouse Associates "Report on the Review of the Cost of Service Methodology" which was commissioned by NCPC. A tabulation of the classification factors used and the rationale supporting them were included in the submission. In several instances, judgement was required on NCPC's part to derive a reasonable estimate of an appropriate classification factor.
7. Where specific assets have been provided to serve a particular customer or customer class, depreciation and rate base were assigned directly to that customer or customer class.
8. All costs classified as demand, energy and customer were then allocated to each customer class, based respectively on each customer class' noncoincident peak demand, kW.h sales plus losses and weighted number of customers. (The weighted number of customers is used so that the additional expense of serving a large industrial or wholesale customer as compared with a residential customer is recognized.)
9. The total revenue requirement for each customer class or specific customer is the sum of:

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1 These terms are defined in the definition section of this report.

allocated demand costs;
allocated energy costs;
allocated customer costs;
specific charges; and
allocated return on rate base; less
allocated miscellaneous revenue credit.

The Board's findings regarding the procedures used by NCPC in its fully distributed cost of service study are provided in the succeeding sections of this chapter. The results of the Board's recommendations are summarized in Tables L-1 to L-7 in Appendix L.

7.1.2 Accounting System

The financial information required for a cost of service study is obtained from the accounting records of an electric utility. NCPC testified that there is no uniform system of accounts for electric utilities in Canada and that the Commission believed that each individual utility in Canada has devised an accounting system best suited to its own situation. The Commission stated that its accounting system is one that developed over time and, although suitable to conduct its operations under the NCPC Act, would nevertheless require some revisions in order to make it more useful for cost of service study purposes.

The Board recognizes that such revisions are complex and would require considerable resource commitments. Nevertheless, the Board encourages NCPC to make the necessary improvements so that costs can be more readily identified by functional and sub-functional categories and segmented in such a way as to be more useful for allocation purposes. Such changes should be instituted at the beginning of a fiscal year.

7.1.3 Allocation of Head and Regional Office Costs to Rate Zones

NCPC's proposed method for allocating head and regional office costs to each rate zone and the Board's recommendations thereon are discussed in Sections 6.6 and 6.7.

7.2 Functionalization Procedures

Intervenors did not express any serious objections regarding the functionalization procedures used by NCPC in its submission. Suggestions were made, however, that NCPC consider making at least the following improvements in the future. It was suggested that, in the hydro rate zones, NCPC should show separately the net plant in service of the hydro assets and the diesel assets rather than grouping them. Distribution-related assets and costs should be sub-functionalized so that assets and costs, such as meters and meter maintenance, which are related solely to serving customers, can be assigned specifically to that classification. Further, demand-related distribution assets and costs should be sub-functionalized to differentiate between services provided at primary and secondary voltage levels. In addition, customer accounting expenses including meter reading, customer service and informational expenses, and sales expenses which vary with customers should be shown separately and should be classified entirely to the customer cost component.

The Board encourages NCPC to make the necessary modifications to its accounting system to accommodate the above suggestions.

7.3 Classification Procedures

The principal issues addressed during the inquiry regarding NCPC's classification procedures were:

1. NCPC's decisions to classify:
    - production rate base in each hydro rate zone 100 percent to demand,
    - production operating costs 95 percent to demand and 5 percent to energy, and
    - distribution assets and costs 80 percent to demand and 20 percent to customer; and
2. the assignment of specific charges to specific customers.

7.3.1 Production Rate Base

On the recommendation of Price Waterhouse as set out in its report to NCPC, the Commission classified its entire production net plant in service 100 percent to demand in each rate zone. The rationale for assigning all production-related facility costs to demand is that these costs, which are incurred to meet capacity requirements, are fixed costs and do not vary with the energy produced by the facility.

Only YTG took exception to NCPC's proposal to classify production assets 100 percent to demand. An expert witness for YTG stated that most Canadian utilities recognize that generation is put in place to meet energy as well as capacity needs and that if generation were only in place to meet capacity it would be installed at minimal cost, i.e., diesel generators or gas turbines would be used. He further stated that the reason more expensive capacity such as hydro is installed is to provide lower cost energy than is possible using diesel generators or gas turbines.

In his direct evidence, the witness indicated that the significance of overemphasizing demand in cost classification is that such an approach penalizes

customer classes with lower than average load factor.

He went on to cite a number of utilities in southern Canada; namely, Ontario Hydro, B.C. Hydro and Manitoba Hydro, which he indicated classify at least 50 percent of their production assets to energy. (It was noted that all of these utilities have sizeable investments in hydro assets.)

He explained that B.C. Hydro uses what he thought could be called a plant factor method to classify production rate base to demand and to energy. He indicated that this method takes the demand imposed on a particular plant at the time of the system's peak and compares that to the average load that the generating plant unit puts forth during the year. He stated that, if applied to Whitehorse No. 4, this method would assign the production rate base 100 percent to energy. He noted, however, that other methods employing plant factors might not lead to that type of result.

He concluded by stating that, at least for the first inquiry into cost-based rates for NCPC, there is merit in a simplistic approach as opposed to one in which a number of plant factors must be justified. He suggested that a simple middle of the road approach that would assign 50 percent to demand and 50 percent to energy might be appropriate.

The expert witness for CAMC stated that the objective of any cost allocation process should be to come up with a fair allocation of costs between high and low load factor customers. This witness indicated that a criticism of the plant factor method is that it causes volatility of pricing because the plant factors of each plant change over time as the system evolves. Thus, the plant factor method can yield allocation factors which vary from year to year.

NCPC testified that it saw merit in moving away from its 100 percent demand classification and assigning perhaps 20 percent of the production asset costs to energy in the hydro rate zones.

The expert witness for Cominco supported NCPC's position. He stated that, based on his experience, he would generally be more comfortable with the 80/20 split suggested by NCPC than with the 50/50 split suggested by the witness for YTG.

Based on the evidence, the Board is of the view that production-related assets in rate zones with large hydroelectric components should not be classified entirely to demand. For the test year, the Board has used the 80 percent demand 20 percent energy split suggested by NCPC in designing cost-based rates in the hydro rate zones.

With respect to the diesel rate zones, the Board notes that no intervenor objected to NCPC's classification of production plant 100 percent to demand. The Board finds this classification acceptable.

7.3.2 Production Operating Expenses

NCPC classified production operating expenditures as being 95 percent demand-related and 5 percent energy-related based on the recommendations contained in the Price Waterhouse report. The APPA Cost Allocation Manual indicates that the classification of operating expenses to cost components generally follows the same classification that is determined for the electric plant function. Production expenses can therefore be classified to demand and energy in accordance with the classification of production rate base to demand and energy.

Since the Board recommends classification of production rate base in the hydro rate zones 80 percent to demand and 20 percent to energy for the test year, the Board also finds it appropriate to similarly classify production operating expenses.

7.3.3 Distribution Rate Base and Expenses

In its submission, NCPC classified distribution assets and expenses as 80 percent demand-related and 20 percent customer-related with no differentiation between primary and secondary levels of service. The NARUC Electric Utility Cost Allocation Manual suggests that distribution costs may be split between demand and customer classifications using one of several acceptable methods, including the minimum intercept and minimum size methods.

The APPA manual describes the minimum intercept method as one which seeks to identify a common investment per customer made in a line transformer related to a no-demand situation. All additional investment costs for a transformer would be related to demand requirements. The minimum size method assumes that the current cost of installing the minimum size pole, conductor, transformer, etc., is reflective of the customer-related portion of investment in distribution plant.

NCPC did not utilize any of the methods suggested in the NARUC manual. The Commission based its customer classification percentage on an examination of NCPC's distribution facilities, with 12 percent being identified as associated with customer metering and an additional 8 percent added to cover service drops and associated equipment.

YECL, in its direct evidence, explained the method it uses to identify an appropriate customer cost. Expert witnesses for other intervenors were generally more

in favour of YECL's analysis because they were of the view that this method is less arbitrary than NCPC's approach.

Cominco's expert witness, when asked if an allocation of 50 percent demand and 50 percent customer would be more reasonable than an 80/20 split in the absence of a more detailed analysis, indicated that he would prefer the 80/20 split. He felt that 50/50 would classify too great a proportion of distribution costs as customer-related. He stated that where distribution systems are fairly concentrated such as those of NCPC in the Northwest Territories, i.e., people are living in small communities and not on farm roads at intervals of a mile apart, the customer component of distribution costs is apt to be rather small.

The Board is persuaded by the evidence to accept NCPC's classification of distribution rate base and expenses for the test year, but recommends that in the future NCPC use a more systematic approach to determine classification factors for the distribution system and that direct assignment and primary/secondary cost separations be made where appropriate.

7.3.4 Specific Charges and Credits

7.3.4.1 Specific Charges

The criterion used by NCPC in assigning assets to specific customers for the purpose of levying special charges was that assets that could reasonably be determined to be for the sole use of a particular customer or particular customer class were charged directly to that customer or class. Assets that fall into this category are facilities installed for a particular customer's need (e.g., the diesel plant installed at Pine Point, NWT for Pine Point Mines Limited's 10 MW electric dragline operation) as well as substation facilities serving individual customers.

In its submission, NCPC did not assign transmission lines to specific customers or classes. Under the proposed rate zone scenario, all transmission facilities within a rate zone were assumed by NCPC to be interconnected. In light of this assumption, NCPC considered it would be inappropriate to charge specific portions of the transmission system to individual customers as this would contradict its theoretical assumption that all consumers, regardless of location in the rate zone, share the same general production and transmission facilities.

7.3.4.2 Specific Charges to Cyprus Anvil Mining Corporation

YECL questioned the reasonableness of the test year specific charges of $8,231 assigned by NCPC to CAMC. YECL filed an extract from NCPC's 1982 filing with the Yukon Electrical Public Utilities Board which identified, for the fiscal year 1982/83, some $845,000 of interest and depreciation associated with assets that appeared to have been specifically assigned by NCPC to only CAMC. A review of the evidence presented in the Board's 1983 inquiry revealed that only $491,635 of the total $845,000 had actually been assigned to CAMC, the remainder having been assigned to various locations served by YECL and to the Town of Faro.

NCPC, when asked what other assets might have been specifically assigned for the test year if it had not taken the approach of considering the two Yukon hydro systems to be interconnected, identified the following assets:

1. the 138 kV transmission line from Takhini substation, just outside of Whitehorse, to Faro would be partially assigned to Carmacks, Town of Faro, CAMC, and Ross River;
2. the 5.2 MW generating plant at Faro would be assigned as a stand-by unit for the Town of Faro and CAMC. As well, it could be partially assigned to Ross River because NCPC could energize that line with that unit; and
3. the Faro to Ross River transmission line would be fully assigned to Ross River.

NCPC stated that if it had not assumed the hydro systems to be interconnected, specific assignments also could have been made in the Mayo system. The line from the Mayo plant to Keno City and to United Keno Hill Mines would be considered a lateral supply and it would have been assigned partly to United Keno Hill Mines and partly to YECL at Keno City.

NCPC outlined further that, in the NWT hydro rate zone, the 138 kV line between Fort Smith and Pine Point could have been assigned to the Town of Pine Point and to Pine Point Mines, and the portion of the line from Pine Point to Fort Resolution could have been assigned to Fort Resolution.

The Board believes that, in the absence of contractual arrangements, established Commission policy, or regulatory decisions requiring a particular customer or group of customers to bear the cost of a new facility, be it a generating facility, transmission line or part of a distribution facility, the annual costs of such facilities should be included in the pooled costs to be allocated to all customers in the rate zone.

Nevertheless, the Board believes that, in light of the circumstances surrounding the construction of the

Whitehorse to Faro transmission line and the 5.2 MW diesel engine at Faro, a significant portion of these assets should, as was done in the past, be specifically assigned to CAMC.

With respect to the 5.2 MW diesel generating unit, the Board is of the view that the annual costs of this unit should be assigned only to CAMC and the communities of Faro and Ross River as it provides no benefits to the other customers in the Yukon hydro rate zone. However, the Board notes that this unit, constructed in 1972, was depreciated using an estimated life of 10 years and therefore was fully depreciated prior to the test year.

Turning to the Whitehorse to Faro transmission line, a review of the 1983 inquiry's transcripts indicate that Whitehorse No. 3 and the transmission line to Faro were built in 1969 as a consequence of an agreement between CAMC and the Government of Canada to build a mining facility at Faro. NCPC was designated to provide some 9.3 MW of additional capacity to supply the new mining operation and to construct a transmission line from Whitehorse to Faro. The Board is doubtful that, in the absence of instructions from the federal government to do so, NCPC would have constructed a 288-kilometre transmission line without requiring some form of guarantee to ensure that existing customers would not be burdened with the cost of this facility if the mine were to shut down.

Further, it would appear that, when the mine was operating, CAMC was assigned in excess of 95 percent of the annual costs of the transmission line with the remaining costs being assigned partly to the towns of Faro, Carmacks, and Ross River. For the fiscal year 1983/84, the annual costs assigned by NCPC to each location and to CAMC are shown in Table 7-1.

Table 7-1

Whitehorse to Faro Transmission Line
Allocation of Annual Costs by NCPC

	1983/84 Annual Cost	Percentage
CAMC	$287,943	96.8
Ross River	1,174	0.4
Carmacks	676	0.2
Faro Townsite	7,623	2.6
Total	**$297,416**	**100.0**

Source: NEB Inquiry EHR-1-83, Exhibit 41.

Because of the unusual circumstances surrounding the construction of the transmission line from Whitehorse to Faro, wherein NCPC, as a result of an agreement between CAMC and the federal government, was instructed to build the transmission line, the Board recommends that this line be treated as a specific asset. The Board further recommends that 85 percent of the annual cost be assigned specifically to CAMC and that the remaining 15 percent be rolled in with the pooled costs in the Yukon hydro rate zone to be allocated to all customer classes based on their respective demands. The 85 percent figure for CAMC reflects the fact that, under this arrangement, CAMC would also be assigned its share of the pooled costs.

Using this approach, $240,890 of the estimated test year cost of $283,401 for the Whitehorse to Faro transmission line has been specifically assigned to CAMC. The derivation of the estimated test year cost of the transmission line is shown in Table 7-2. The Board recommends that this amount be recovered from CAMC in 12 equal monthly installments.

Table 7-2

Whitehorse to Faro Transmission Line
Estimate of Specific Costs for the Test Year

Asset	In-Service Year	Asset Life	Annual Straight-line Depreciation	Average Net Book Value
Transmission Line (original cost $3,416,150)	1970	30	$113,872	$1,537,262
Right-of-Way (original cost $563,717)	1970	20	28,186	98,648
			$142,058	**$1,635,910**

Annual Straight-line Depreciation Expense	$142,058
Return (8.64% x $1,635,910)	141,343
Total Annual Costs	**$283,401**
Assigned to CAMC ($283,401 x 0.85)	**$240,890**

7.3.4.3 Specific Charges to Pine Point Mines

In 1979, NCPC installed three 2.5 MW Ruston diesels at Pine Point under an agreement between NCPC and Pine Point Mines whereby the mine agreed to pay for the capital and interest costs of these facilities.

In its submission, NCPC assigned specific charges to Pine Point Mines amounting to the payment due to NCPC in 1985/86 under the agreement. Although Pine Point Mines did not express any concern

regarding the annual amount due under the agreement and assigned to it in the submission, it did, as discussed in Section 8.3.7.1, question whether the amount should be paid in monthly or annual installments.

7.3.4.4 Specific Credits

NCPC provides a specific credit to only one customer on its system: Con Mine in the NWT hydro rate zone. A credit of $9,500 has been applied to the cost of service of Con Mine to compensate for the wheeling of power on the Con transmission line. This amount has been charged back to the residential, commercial and wholesale rate groups as these groups benefit from this wheeling of power. The Board notes that no intervenor raised any objection to this credit and the Board finds the amount of the credit to be acceptable for the test year.

YECL, in final argument, argued that it ought to receive a similar credit for services supplied at Carmacks, Ross River and Haines Junction where it owns the step-down substations, whereas at other locations the transformer facilities are owned by NCPC and provide service to YECL and industrial customers at step-down voltages. The Board recommends that NCPC consider the appropriateness of granting such a credit to YECL in the future.

7.4 Allocation Procedures

Having functionalized and classified rate base and revenue requirement, the final step in the cost of service study is to allocate the classified costs to the various customer classes using appropriate demand, energy and customer allocation factors.

A number of issues were raised regarding NCPC's approach to cost allocation. These are dealt with in succeeding sections and are as follows:

1. NCPC's failure to allocate demand or customer costs to secondary industrial (interruptible) users (Section 7.4.1);
2. NCPC's incremental approach which underallocated costs to the street lighting class (Section 7.4.2);
3. NCPC's method of calculating the noncoincident peak demands of the residential and commercial classes (Section 7.4.3.1);
4. NCPC's use of an instantaneous demand meter to determine Con Mine's noncoincident peak demand (Section 7.4.3.3);
5. the inconsistency of using kilowatts and kilovolt amperes as the basis for allocating costs to customer classes (Section 7.4.3.4);
6. NCPC's exclusion of internal sales in determining energy sales for cost allocation purposes (Section 7.5);
7. the failure of NCPC to attempt to segregate distribution line losses from transmission line losses (Section 7.6); and
8. NCPC's customer weighting factors for the wholesale, and primary and secondary industrial classes (Section 7.7).

7.4.1 Industrial Secondary Class (Interruptible Service)

In the Yukon hydro rate zone, NCPC provides energy on an interruptible basis to United Keno Hill Mines and the Whitehorse Hospital for electric boiler consumption. In its submission, NCPC allocated only energy costs to the interruptible service. No demand or customer costs were allocated to this service.

Considerable concern was expressed by intervenors over the proposed rate for interruptible service. A number of intervenors were of the view that demand and customer costs should also be allocated to the class because the current excess capacity in the Yukon hydro rate zone suggests that the interruptible service will likely be without interruption and will, therefore, be virtually guaranteed the same service provided to others by NCPC. Concern was also expressed that, with a rate of 0.961¢ per kW.h and little likelihood of interruption, NCPC would be inundated with requests for interruptible service, leaving the remaining firm service customers to pick up all the demand- and customer-related costs of the system.

Based upon the Board's recommendation in Section 8.3.6 that the rates for the test year for interruptible service be set at 3.49¢ per kW.h for Whitehorse Hospital and 2.58¢ per kW.h for UKHM, the Board has estimated NCPC's test year revenue from interruptible sales to be $1,000,310 comprised of $270,900 from sales to United Keno Hill Mines and $729,410 from the Whitehorse area.[1]

Although the Board is recommending value-of-service pricing in determining the rates for customers in this class (see Section 8.3.6), the Board is of the opinion that, for cost allocation, the interruptible customer class should be assigned both energy

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1 NCPC stated it is hopeful of providing electricity for boiler purposes to other customers in the Whitehorse area during the test year. Since rates for these customers have not been established, the Board has applied the Whitehorse Hospital rate to all expected sales in the Whitehorse area.

and customer costs and where appropriate a portion of demand costs in order that proper costs for the other customer classes can be determined.

The Board believes that the allocation of costs to the interruptible class can be accomplished by first treating the interruptible class like any other class for the purpose of allocating energy and customer costs. Then, having determined beforehand the value-of-service price and therefore the projected revenue associated with providing interruptible service, the amount of the demand costs to be allocated to this class would be the remainder after deducting the allocated energy and customer costs from the forecast interruptible sales revenue. After deducting the interruptible class' share, the remaining demand-related costs in the rate zone would be allocated to the other classes based on their respective noncoincident demands.

7.4.2 Street Lighting

In its submission, NCPC proposed to treat street lighting on an incremental basis for cost allocation purposes. Using this approach, NCPC did not assign any joint rate base related to production, transmission or distribution, nor any joint costs relating to transmission, distribution or support facilities to the street lighting class. The Price Waterhouse report noted that this methodology represented a departure from NCPC's current practice of treating street lighting like any other customer class, wherein demand costs are allocated to street lighting on the basis of kW demand, energy costs are assigned on the basis of kW.h consumed plus losses, and customer costs are allocated assuming that street lighting represents one customer.

Intervenors were opposed to NCPC's proposed incremental approach for two reasons: first, street lighting contributes to the system peak in the North; and second, when using the noncoincident peak method of allocation, no class should be exempt from demand charges.

Based on the evidence, the Board recommends that NCPC's proposed incremental approach be rejected and that the Commission continue its current practice of treating street lighting like any other class for cost allocation purposes. In assigning customer costs to street lighting, the Board, for cost allocation purposes, has deemed street lighting to represent one customer in each community where NCPC provides such service. In deriving the revenue requirement for street lighting, the Board made specific assignments for direct maintenance, head and regional office administration, depreciation and return. In addition, functionalized costs, excluding head and regional office costs, were allocated to the street lighting class using demand, energy, and customer factors.

7.4.3 Demand Cost Allocation Factors

The allocation of demand-related costs to customer classes is based on the relative demand placed on the electric utility system by each customer class. NCPC has used the noncoincident peak method of determining the relative demand of each customer class.

Intervenors agreed that, for the time being, NCPC should continue to use the noncoincident peak method for allocating demand costs. However, intervenors did raise a number of concerns regarding the calculation of noncoincident peak demands for the street lighting, residential and commercial classes, and for Con Mine.

As discussed in Section 7.4.2, the Board has recommended that street lighting be treated like any other customer class. The Board, therefore, recommends that street lighting be assigned demand costs based on its noncoincident peak demand.

7.4.3.1 Residential and Commercial Demands

Since all of NCPC's industrial and wholesale customers in the hydro zones are demand-metered, NCPC had available to it the noncoincident peak demands of each of the customers in these two classes. However, none of NCPC's residential customers are demand-metered, and the proportion of NCPC's commercial customers who are demand-metered ranges from 5 to 65 percent in the various rate zones. Therefore, in its submission, NCPC resorted to a formula that applies the load factor of the customer class to the kW.h sales and losses of the class to calculate the commercial and residential noncoincident demands. The load factors of the commercial and residential classes were assumed by NCPC to be equal to the system load factor plus one percent and the system load factor minus one percent, respectively.

During cross-examination, NCPC was unable to substantiate the $\pm$ 1% formula, except to say that it had previously been recommended to the Commission.

Many intervenors took issue with NCPC's manner of calculating the residential and commercial demands, suggesting that the $\pm$ 1% factor was unrealistic and that the application of such a formula understates the demands of the two classes.

YECL was the first intervenor to address its concerns regarding the $\pm$ 1% formula. A witness for YECL

stated that he had never before seen that method. In his cost of service study, he used residential and commercial load factors of 55 percent and 66 percent respectively. His judgement came from load research that Alberta Power Limited had done on communities in Alberta, which indicated that load factors for the residential class would vary from 45 percent to 55 percent and for the general service class from 50 percent to 80 percent.

An expert witness representing YTG echoed the concerns of YECL. In his study, he used load factor estimates of 34 percent for the residential and small commercial customer classes and 45 percent for large commercial customers, which he stated were based upon estimates made by Saskatchewan Power Corporation. Upon further review, he believed these load factors to be a bit low. He suggested that the load factors might be closer to 38 percent for small customer groups in Quebec and in the 50 percent range for retail class customers in Newfoundland. In B.C. and Ontario, based on coincident load factors, which he would expect to be a little higher than the class noncoincident load factors, the range was 47 percent to 50 percent.

NCPC, when asked what might be reasonable load factors for these two classes, suggested load factors ranging from 45 to 55 percent for residential customers and from 50 to 60 percent for commercial customers.

The witness for YTG considered these ranges to be acceptable and concluded his comments on this topic by stating that, in light of the evidence, he would suggest that the commercial load factor should be quite a lot higher than the residential load factor. He thought that one could adopt a ten percentage point spread in load factor, for the test year, and "move forward until somebody has some better evidence".

Cominco's expert witness also took exception to NCPC's ± 1% formula and introduced another method of determining noncoincident demands for these two classes of customers.

He stated that billing demands comprised of both estimates and, where available, meter readings provide a fair approximation of the actual noncoincident demands placed on the system by the commercial class. This witness proposed that, since such information is available, that it be used for cost allocation. However, he noted that the billing demands in NCPC's addendum to its submission are an average for the year and that the true peak demand of the customers are actually somewhat higher. Using an estimate of a peak-to-average factor of 1/.85, he adjusted the average demands upwards to represent peak demands for the test year.

Turning to residential demands, this witness, in a revised Appendix II to Cominco's direct evidence, indicated that, based on research conducted elsewhere, the average customer contribution to system coincident peak demand would be 2.6 kW, or 4 350 kW for the class in the NWT hydro rate zone.[1]

However, he noted that the residential class does not necessarily peak when the system peaks. Using a system coincidence factor of 0.84, he adjusted the residential demand in his example upwards to its class coincident peak demand of 5 179 kW. He then recognized that not all customers within the residential class peak at the same time. To adjust for this, he used a class coincidence factor of 0.81 to arrive at a noncoincident peak of 6 394 kW. He made this adjustment so that the residential customers would be treated in a manner consistent with NCPC's treatment of industrial and wholesale customers, where each individual customer's demand was summed to obtain a noncoincident peak demand of the class. In his original appendix, the witness noted that NCPC did not adjust its load factor formula by a class coincidence factor and, therefore, the results of NCPC's formula represent the coincident demand of the class; not the noncoincident demand.

The Board notes that the effect on many of the customer classes of adopting the methods proposed by the witness for Cominco in place of NCPC's ± 1% method could be dramatic. The Board also notes that the methods proposed by Cominco require that several parameters be estimated (i.e., system coincidence factor, class coincidence factor, average residential demand at system peak, and peak-to-average factor). Cominco's proposal was only introduced as evidence in the proceedings after the direct and cross-examination of NCPC and all other intervenors (except GNWT) had been completed. The Board believes that, although the methodology proposed by Cominco may have merit, there is a lack of evidence to support the adjustment factors (particularly a lack of data applicable to operations North of 60°) and further that such factors should be subject to full and proper examination by all interested parties before being recommended for implementation.

The Board, after considering the evidence, recommends that, for the test year, NCPC retain the use of a load factor approach for determining residential

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1 Cominco's expert witness used the NWT hydro rate zone as an example: 1,673 customers x 2.6 kW/customer = 4 350 kW.

and commercial demands in each rate zone, but that the load factors reflect a more realistic spread of 10 percentage points as suggested by the expert witness for YTG. The Board, in determining cost-based rates for the test year, has used load factors of 45 and 55 percent for the residential and commercial classes, respectively, in each rate zone. The Board notes that these load factors are within the ranges suggested by NCPC and intervenors.

7.4.3.2 Industrial and Wholesale Demands - NWT Diesel Rate Zone

NCPC also used a formula to calculate the demands of the industrial and wholesale customers in the NWT diesel rate zone. In the formula, the load factors of the two classes were assumed by NCPC to equal the system load factor of 55.8 percent.

No intervenor raised any concern regarding NCPC's method of determining demands for the wholesale and industrial classes in the NWT diesel rate zone. Therefore, the Board accepts the load factors as determined by NCPC for the test year.

7.4.3.3 Con Mine Demand

During the inquiry, NCPC indicated that it measures Con Mine's demand using an instantaneous demand meter, whereas the Commission measures all other major customers' demands using 15-minute average demand meters.

The Board notes that the metered demands of NCPC's major customers formed the basis of the Commission's forecast of test year demands for each of these customers.

In its direct evidence, Con Mine indicated that, with its demand being metered using an instantaneous meter, it felt it was being discriminated against.

NCPC indicated that it allows Con to skip ore only during the period between 8:00 p.m. and 7:00 a.m. and explained that, when Con is skipping ore, the mine can have an instantaneous peak requirement of up to 4.7 MW in a period of approximately a minute and a half or a swing of approximately 2.7 MW. NCPC stated that, even though Con is allowed to skip ore only during the off-peak period, NCPC must nevertheless use diesel generation to meet its peak during the winter period. As a result, NCPC indicated that it must keep additional diesel generation on the system not only to provide Con with capacity, but also to take the swings.

Cominco acknowledged that Con's peak demand occurs when the mine is skipping ore or waste from the mine. However, Con argued that because the mine is allowed to skip only in the off-peak period, its demand does not contribute to the overall system peak. Further, when Con wishes to skip ore, it must get prior approval from NCPC. Cominco also pointed out that, when NCPC has a problem on its system, Con is the first load to be dropped and the last to come back on. Finally, Cominco noted that, if NCPC's system fails, NCPC draws on Con's power source for NCPC's other customers. Cominco acknowledged that under this arrangement a credit is given automatically by the meter but that there is no recognition given to the stand-by nature of Con's facilities.

In final argument, Cominco submitted that Con should not be discriminated against in terms of a different type of meter and, if anything, Con should receive preferential treatment in recognition of its stand-by function and the restrictions which are imposed on it and not on the other industrial customers. However, Cominco was also of the view that, if there were any additional facilities put in place or put in on a stand-by basis specifically to serve Con Mine, the costs of those should be recognized in Con's rates.

The City of Yellowknife and ICG indicated that, in the past, the NWT Public Utilities Board had approved NCPC's use of an instantaneous demand meter for Con. These two intervenors argued that, in the absence of any compelling new evidence to the contrary, NCPC should continue to use an instantaneous demand meter for Con Mine.

The Board is of the view that, in determining the appropriate demand for Con Mine for cost allocation, all factors must be taken into consideration including the restrictions placed on the mine's utilization of its hoist and the stand-by nature of Con's power facility. Accordingly, the Board recommends that Con's non-coincident peak demand for cost allocation be determined on the basis of a 15-minute interval.

During the inquiry, Cominco indicated that it believed that an appropriate 15-minute demand for the mine could be arrived at by subtracting 900 kV.A from the demand measured by the instantaneous demand meter. Cominco indicated that this figure was based on the results of a report done by Thomas Associates in which the figure of 900 kV.A was determined by actual measurement.

The Board accepts this adjustment as reasonable and, accordingly, has decreased Con Mine's non-coincident demand for the test year by 900 kV.A. However, in recommending that Con's demand in the future be determined on the basis of a 15-minute interval, the Board also recommends that Con's

future rates should reflect any incremental costs that can be directly attributed to the demands placed on NCPC's system in providing power to accommodate Con's ore-skipping operation.

7.4.3.4 kW vs. kV.A

NCPC testified that the demands of its major wholesale customers, industrial customers with the exception of Pine Point Mines and Dome Petroleum Limited (Dome), and some of its commercial customers are measured and expressed in kV.A. The demands of all other customers are either estimated or measured and expressed in kWs.[1] NCPC acknowledged that, in the cost allocation and rate design sections of its submission, it had used kWs and kV.As interchangeably. As such, NCPC had implicitly assumed a one-to-one relationship between kWs and kV.As. The Board notes that the true relationship is that kWs equal kV.As times power factor. Therefore, kWs equal kV.As only when the power factor of the customer or class is unity.

Intervenors and NCPC agreed that, ideally, to avoid inter-class inequities, the demands of all classes for cost allocation purposes should be expressed in a common unit of measurement.

The Board agrees that, ideally, the demands of all customer classes should be expressed in the same units of measurement for cost allocation purposes (be it kWs or kV.As) and therefore, recommends that NCPC consider using only one or the other in future submissions. However, for the test year, the Board, in determining the demands for each customer class, has not converted NCPC's kWs to kV.As or vice versa, with the exception of Pine Point Mines' demand.

NCPC indicated during the inquiry that the demands of two of its three industrial class customers in the NWT hydro rate zone; namely, Con Mine and Giant Yellowknife Mines Ltd., were expressed in kV.As, whereas the demand of the third customer, Pine Point Mines, was expressed in kWs.

The Board believes that, where a class is comprised of so few customers, expressing the demands of all but one customer in kV.As creates an obvious intra-class inequity.

During cross-examination, NCPC indicated that it believed the power factor of Pine Point Mines to be roughly .95. The Board notes that Pine Point Mines did not challenge this figure and further that Cominco's expert witness believed that demand costs should be allocated to customer classes on the basis of kV.A demand.

The Board believes that, where administratively practicable, intra-class inequities should be eliminated and therefore, recommends that, for cost allocation and rate design purposes, Pine Point Mines' demand in the test year be expressed in kV.A. Accordingly, the Board has divided Pine Point Mines' kW demand by .95 to arrive at an equivalent demand expressed in kV.As.

7.4.3.5 Determination of Demands in Future

Having reviewed specific concerns as outlined in Sections 7.4.3 to 7.4.3.4, the Board recommends that NCPC should examine various methods of determining demands for the residential and commercial customers in all zones and for the wholesale and industrial customers in the NWT diesel rate zone with a view to coming up with more appropriate demands for these classes in the future, and further, that NCPC be able to justify whatever method it incorporates in future submissions.

7.5 Internal Sales

In determining energy sales for residential customers in each rate zone for the test year, NCPC excluded energy sales to its own employees. Intervenors took the position that these sales, referred to as internal sales by NCPC, should have been included in residential energy sales for cost allocation and rate design purposes.

NCPC testified that, in light of its current utility benefit package with its employees, it considers internal sales to be similar to energy consumed in its plants in that it is effectively a cost of doing business. Presently, NCPC charges each employee, excluding those in head office, a flat amount of $70 per month for utilities, with NCPC picking up the total cost of each employee's utilities.

In NCPC's opinion, this is an untenable situation for it to be in. NCPC, in effect, has no control over the amount of assistance it provides to each employee because at a flat rate of $70 per month regardless of consumption, the employees have no incentive to conserve energy. NCPC, therefore, is taking steps to alleviate this situation. During cross-examination, NCPC indicated that it proposes to implement a utility user-pay program for employees in the Yukon and NWT hydro rate zones in the test year. Such a plan would roll into the employee wage package an acceptable level of offset of remuneration that would

1 kV.As recognize the reactive power drawn from the system by the customer whereas kWs do not. Depending upon the customer's power factor, kV.As equal or exceed kWs.

compensate for the current utility package, but would require the employee to pay his own utility bills.

Because NCPC included, in its submission, a utility offset amount in wages and salaries in both hydro rate zones, NCPC agreed that employees in these two zones should be considered as normal bill-paying electric utility residential customers in the test year, and that, therefore, it would be appropriate to include energy sales to the employees (i.e., internal sales) in determining total residential energy sales. However, since NCPC is not proposing to implement the new benefit package in the diesel rate zones, NCPC was of the view that it should continue to exclude internal sales in estimating energy sales for residential customers in those rate zones.

The Board concurs with NCPC's position regarding the treatment of internal sales for cost allocation and rate design purposes in the diesel rate zones, and with NCPC's views on including internal sales in residential sales in the hydro rate zones. The Board, therefore, has adjusted upwards only NCPC's estimate of the residential energy sales in the hydro rate zones to include internal sales in the test year.

7.6 Allocation of Line Losses

Energy costs are allocated to customer classes in a cost of service analysis according to their respective kilowatt-hour sales including system losses. When allocating system losses to customer classes in its submission, NCPC made no attempt to differentiate between losses on transmission lines and losses on distribution lines. Total line losses in each rate zone were simply allocated to all classes based on the ratio of each class' energy consumption to total sales.

A number of intervenors took exception to NCPC's approach because it effectively assigned a portion of distribution losses to the wholesale and industrial classes which do not use the distribution facilities. They argued that distribution losses should be allocated only to the residential, general service and street lighting categories.

NCPC agreed with this approach, but indicated that it does not have metering that would identify separately distribution and transmission losses, nor had it attempted to estimate such losses.

A witness for YECL suggested that NCPC use a loss factor of ten percent of sales to determine distribution losses. This factor was based on his company's experience of supplying electricity in Yukon. Witnesses for other intervenors supported the reasonablensss of this factor and a witness for NCPC thought that a distribution loss factor of 10 to 12 percent of sales would be reasonable.

While in due course one could look to better estimates from NCPC upon which to base distribution line losses in each rate zone, the Board recommends that, for the test year, NCPC use a loss factor of 10 percent of sales to the residential, general service and street lighting classes to determine distribution losses attributable to those classes. Further, the resulting transmission losses in each rate zone (total losses minus distribution losses) should be apportioned to each class in the rate zone based upon its ratio of energy sales plus distribution losses (if any) to total energy sales plus distribution losses in the zone.

7.7 Customer Weighting Factors

The allocation of customer costs to customer classes is based on the number of customers in each class multiplied by appropriate weighting factors to reflect differences in the costs of providing service to the various classes. For example, the NARUC manual indicates that the capital cost of meters is a cost requiring weighting for different classes because the metering arrangement for a single industrial customer may be 20 to 80 times as costly as the metering for a single residential customer.

7.7.1 Wholesale and Industrial (Primary) Classes

As a guide to determining appropriate weighting factors for assigning customer-related costs to the industrial (primary) and wholesale classes in the hydro rate zones and the industrial (primary) class in the NWT diesel rate zone, NCPC used a method which considered the installed capital cost of metering. This method yielded a ratio of 115 to 1 for wholesale and industrial (primary) customers compared to residential and commercial customers. NCPC did not, however, believe that a factor based solely on metering costs was a reasonable basis for allocating all customer costs to these classes and, therefore, chose a weighting of 80 which NCPC believed to be comparable to the upper limit of the 20 to 80 range suggested in the NARUC manual.

In response to an information request, NCPC indicated that customer-related expenses for industrial (primary) and wholesale customers exceed those for residential and general service customers by an approximate factor of 22 for metering-related costs and by a factor of 50 to 60 for other customer-related costs.

NCPC agreed that, if the weighted average of meter-related and other customer-related costs were calculated, the customer costs for industrial (primary) and wholesale customers would exceed those for residential and general service customers by a factor of only 45 to 55.

Intervenors also questioned the reasonableness of the weighting factor used by NCPC. Cominco's expert witness performed his own analysis, the results of which suggested to him a range of 38 to 50.

Based on the evidence, the Board recommends that, for the test year, a weighting factor of 50 be used for assigning customer-related costs to the wholesale and industrial (primary) classes in each hydro rate zone and to the industrial (primary) class in the NWT diesel rate zone.

It was also noted that, in the NWT diesel rate zone, NCPC has classified some 50 customers as being "wholesale" for cost allocation purposes, but has assigned them a class weighting factor of only one. NCPC explained that the "wholesale" designation was used simply to distinguish these customers (Transport Canada and GNWT), which are supplied at primary voltage and provide their own secondary transformation and distribution, from other commercial customers using NCPC's distribution system. The Board finds NCPC's weighting factor for the "wholesale" class in the NWT diesel rate zone to be acceptable.

7.7.2 Industrial (Secondary) Class

In the Yukon hydro rate zone, NCPC did not allocate any customer-related costs to industrial (secondary) customers. NCPC indicated that, if it were deemed appropriate to allocate such costs to the secondary class, a weighting factor of 10 might be more appropriate than a factor of 80 because the customers in this class are not demand-metered as are primary industrial customers and the customer bill for one such customer is calculated by hand.

The Board recommends that a weighting factor of 10 be used for the test year for assigning customer-related costs to this class.

7.7.3 Number of Customers

NCPC stated that the number of customers projected for the test year as presented in the submission was the actual number of customers serviced as at 31 March 1984. During cross-examination, NCPC indicated that the number of customers in certain communities, particularly Dawson, Yukon, varies from summer to winter. NCPC agreed that, for cost allocation purposes, it would have been more appropriate to weight the number of customers during the year rather than taking the count at one point in time.

The Board recommends that, in the future, NCPC use a 12-month average to determine the number of customers in each class in each rate zone for cost allocation purposes.

7.7.3.1 NWT Diesel Rate Zone

In its submission, NCPC used seven as the number of industrial customers for cost allocation purposes, but used five in the design of rates for this class.

NCPC acknowledged that it had assumed that two services at Norman Wells for Esso Resources Canada Limited would have no consumption in the test year but would remain connected. However, these two services were subsequently disconnected in the fall of 1984.

Accordingly, the Board has used five as the number of customers for both cost allocation and rate design purposes.

7.8 NWT Heat and Water & Sewerage Rate Zones

In addition to providing electric utility service, NCPC provides a heat service at Inuvik and Frobisher Bay, and a water & sewage service at Inuvik. NCPC distributes the heat at Inuvik. At Frobisher Bay, the Commission provides heat on a wholesale basis to GNWT for subsequent distribution by the government.

NCPC's plant at Inuvik houses facilities for all three utility services while the plant at Frobisher Bay supports the electricity and heat services.

In its submission, NCPC assigned specific water & sewerage and heat-related equipment directly to each utility service. The powerhouse and equipment common to all services were allocated on the basis of the relative floor area occupied by each utility service in the powerhouse. A further allocation of production fuel costs at Inuvik was then made between heat and water & sewerage on the basis of the BTUs utilized by each service.

The fuel tanks and fuel handling equipment common to the services were allocated on the basis of the relative fuel consumption of each service. Having determined the total rate base for each service, NCPC allocated an appropriate return on rate base.

NCPC allocated head and regional office costs to the heat and water & sewerage rate zones on the basis of direct salaries and wages. Specific operating costs were identified and assigned directly to the heat and water & sewerage rate zones. Common operating costs were allocated between services using factors estimated by the superintendent at each plant.

The Board accepts as reasonable the allocation methodology used in the submission for the heat and water & sewerage rate zones with the exception of the head and regional office allocations. The recommended method of allocating these costs is outlined in Sections 6.6 and 6.7.

Chapter 8
Rate Design

The Board's comments and recommendations regarding NCPC's rate design for each customer class are presented in the succeeding sections of this chapter. The rates proposed by NCPC for each customer class in each rate zone are shown in Tables 8-1 to 8-7 at the end of this chapter. Also shown in each table are the rates recommended by the Board after giving effect to the recommendations set out in Chapters 4 through 8 of this report.

8.1 Contracts

NCPC indicated that it has supply agreements with two of its major industrial customers; namely, CAMC and Pine Point Mines. These contracts specify, amongst other things, charges which NCPC may impose, and/or the manner in which such charges are to be calculated and the basis upon which the charges are to be levied. The Board is of the view that, for the purposes of determining cost-based rates for NCPC, specifics of rates and their design as stipulated in contracts ideally must be overlooked.

The Board recognizes, however, that the agreement with Pine Point Mines also includes a payment schedule related to a 7.5 MW diesel plant installed by NCPC specifically for the mine. The schedule specifies payments to be made by the mine in respect of principal and interest on NCPC's investment in the plant. It is the Board's view that costs related to customer-specific assets should be paid for only by the benefiting customers and not passed on to others. Therefore, the Board believes that the payment schedule for the 7.5 MW diesel plant, which has been agreed to by Pine Point Mines and NCPC, should be respected and assessed to the mine as a specific charge (see Section 8.3.7.1).

8.2 Johnson's Crossing

As explained in Sections 4.7 and 6.2.4, the Board is not convinced that NCPC will construct a transmission line from Whitehorse to Johnson's Crossing during the test year. The Board has nevertheless left the revenue requirement (as adjusted) of Johnson's Crossing in the Yukon hydro rate zone for the test year for the reasons outlined in Sections 4.7 and 6.2.4. However, the Board believes that, as long as Johnson's Crossing continues to be served by NCPC via diesel generation, NCPC's customers at Johnson's Crossing should be charged the rates designed for the Yukon diesel rate zone.

8.3 Electric Utility Rates

8.3.1 Billing Demand - Units of Measurement

In its submission, NCPC expressed all demand charges on the basis of kV.As, although the Commission acknowledged during the inquiry that it expected to bill some customers on the basis of kWs.

In its direct evidence, CAMC argued that all demand charges should be levied on the basis of kWs, with a safeguard provision to bill on kWs or 90 percent of kV.As, whichever is greater. CAMC submitted that the kW and not the kV.A is the complement of kW.h (the basis on which energy is charged) and that, for consistency, the kW should be used for billing demand.

NCPC argued that kWs do not recognize the reactive power which it must supply, particularly to its larger customers. NCPC indicated that, since kV.As recognize such power, it was more accurate to use kV.As for billing the larger customers. NCPC submitted that for its smaller customers, for whom it was difficult to obtain kV.A meters and for whom the difference between kWs and kV.As would not be as significant, it was suitable to bill on the basis of kWs. An expert witness for Cominco agreed with NCPC that billing for demand on the basis of kV.As is appropriate for large customers, who can be expected to take measures to control their power factor. The witness also agreed with NCPC's argument for the use of kWs for smaller general service customers, stating that small customers either may be unable to control their power factor, or do not have a large enough load to make taking corrective action worth their while.[1]

1 Note: Residential customers' demands are not metered.

The Board is not persuaded by CAMC's argument for basing billing demand on number of kWs. The Board agrees with NCPC that, as a general rule, large loads should be metered in kV.As in order to recognize the reactive power drawn from the system by the customer. The Board believes, however, that for smaller loads, for which it is impractical to install kV.A meters and for whom the difference between kWs and kV.As among customers within the class would not be as large, billing on the basis of kWs is suitable. These overall views regarding the appropriate units of billing demand are reflected in the succeeding rate design sections for the various customer classes.

8.3.2 Residential Rates

In its submission, the residential rates proposed by NCPC consisted of a monthly customer charge and a declining block energy rate with blocks for the first 700 kW.h; the next 500 kW.h; and all consumption over 1 200 kW.h. The customer charge, expressed in dollars per customer per month, was set below the customer costs allocated to the class expressed on a per customer per month basis. However, NCPC also proposed a minimum monthly bill equal to the allocated customer costs. For monthly consumptions resulting in a total bill in excess of the minimum bill, the component of the customer cost unrecovered through NCPC's proposed customer charge was recovered through the energy charge.

In NCPC's design of the rates, both the energy and demand components of a customer's bill were assumed to vary directly with kW.h of consumption. Therefore, the component of the customer cost unrecovered in the customer charge and recovered instead through the energy charges resulted in NCPC's proposed declining block rates.

The Board believes that the use of a customer charge which does not fully recover customer costs, as well as the use of a separately defined minimum bill, are unnecessary complications in the rate structure. The Board is of the opinion that NCPC should collect the customer costs in full via a fixed monthly customer charge. The Board, therefore, recommends that the customer charge be set equal to the allocated customer costs per customer per month and that the customer charge be the minimum bill. The Board notes that, by fully recovering customer costs through the customer charge, all energy and demand costs can be recovered through a single charge per kW.h thus removing the need for declining blocks.

8.3.3 General Service Rates

In its rate design, NCPC subdivided the general service class (referred to as the "commercial class" by NCPC) into two groups: small general service and large general service. NCPC defined the large general service customers as being those general service customers having demands of 40 kV.A and above.

To design rates for the two general service groups, NCPC first designed an initial single rate schedule which was based upon the costs allocated to the commercial class as a whole. Adjustments were then made to the initial rate schedule to arrive at separate rate schedules for the small and large general service groups.

NCPC's proposed small general service rate consisted of a single demand charge, a minimum monthly bill, and declining block rates with blocks for the first 900 kW.h; the next 1 600 kW.h; and all consumption over 2 500 kW.h.

NCPC's proposed large general service rate consisted of a monthly customer charge, a minimum monthly bill based on kV.A of demand, and declining kW.h charges for blocks of the first 50 kW.h/kV.A; the next 200 kW.h/kV.A; and all consumption over 250 kW.h/kV.A.

NCPC explained that it distinguished between small and large general service customers in order to design rates which the Commission felt reflected the rate structure preferences of the two groups.

The Board is not persuaded that a distinction between small and large general service customers is warranted. The Board notes that NCPC's current rates make no such distinction and that, for cost allocation purposes, NCPC allocated costs to the commercial class only as a whole. The Board also believes that the distinction between small and large general service and the differently structured rates for each greatly hamper the understandability of NCPC's rates by commercial customers. Accordingly, the Board recommends that rates be designed for the general service class as a whole in each rate zone.

The Board agrees with NCPC that the rate structure for the general service class should include a demand element, so that commercial customers are given an incentive to improve their load factors. The Board believes that this can best be accomplished, with regard to ease of administration and understandability, through a separate demand charge. This charge would be derived by dividing the allocated demand costs by the projected billing demand of the commercial class.[1] NCPC indicated that, of those general service customers whose demands are metered, as a general rule only the cus-

1 For the test year, the Board used the billing demands found in the addendum to NCPC's submission.

tomers with the larger loads are metered in kV.A, while the remaining majority are metered in kW. In view of this, the Board recommends that the demand charge be levied on the basis of kW or kV.A, whichever is metered or estimated.

The Board is of the opinion that understandability and ease of administration, while ensuring recovery of costs, can further be promoted by collecting the customer and energy costs allocated to the commercial class through separate charges as well. The Board therefore recommends that, in addition to the demand charge, a single customer charge be designed to recover allocated customer costs and a uniform energy charge per kW.h be designed to recover the allocated energy costs.

8.3.4 Industrial Rates

In its submission, NCPC proposed industrial rates consisting of a single demand charge designed to recover customer and demand costs, and a uniform energy charge designed to recover allocated energy costs.

The Board finds NCPC's method of designing industrial rates to be reasonable.

8.3.4.1 NWT Hydro Rate Zone

During the inquiry, NCPC indicated that, in the NWT hydro rate zone, Pine Point Mines is metered for demand in kWs, whereas the other customers in the class are demand-metered in kV.As. The Board notes that, although NCPC's proposed demand charge for the industrial class was expressed on a dollars per kV.A basis, such charge was actually derived using a mixture of kWs and kV.As of demand. The Board believes that designing the rates in this manner gives an unnecessary advantage to Pine Point Mines relative to the two other customers in the class. The Board therefore recommends that a power factor of .95 (see Section 7.4.3.4) be used to convert Pine Point Mines' kW billing demand to kV.As. The resultant demand charge is thereby appropriately expressed in dollars per kV.A, and all the customers are treated on an equal basis in arriving at the charge. Recognizing, nevertheless, that Pine Point Mines' demand will in fact be metered in kWs, the Board further recommends that the resultant demand charge per kV.A be divided by .95 to arrive at an equivalent charge per kW for the mine. The Board also suggests that, to avoid adjusting the demand charge for the mine in the future in order to maintain parity within the class, NCPC consider metering Pine Point Mines' demand in kV.A.

In calculating its recommended rates for the NWT hydro rate zone industrial class, the Board also adjusted NCPC's forecast of Con Mine's billing demand. The Board reduced the billing demand of Con Mine by 900 kV.A to reflect the Board's recommendation that NCPC base the mine's demand on a 15-minute interval rather than on its metered instantaneous demand (see Section 7.4.3.3). As long as NCPC continues to use the instantaneous demand meter for Con, the Board believes that adjustments should be made to the demand charge for Con so that NCPC recovers the same revenue from the charge as it would if Con's demand were metered using a 15-minute demand meter. The Board also recommends that, in the future, any incremental costs incurred by NCPC which can be directly attributed to the demand placed on NCPC's system by Con's ore-skipping operations be recovered from the mine through a customer-specific charge.

8.3.4.2 NWT Diesel Rate Zone

NCPC's proposed demand charge for the NWT diesel rate zone industrial class was expressed in dollars per kV.A, although kW billing demand was used to derive the charge. The Board notes that, according to the submission, Dome is the only industrial customer expected to be served by NCPC in the zone during the test year. During the inquiry, NCPC indicated that the demand at each of NCPC's service points to Dome is either metered or estimated in terms of kWs. The Board therefore believes that it is suitable to express the NWT diesel industrial demand charge in terms of kWs rather than kV.As for the test year.

8.3.4.3 Yukon Hydro Rate Zone

NCPC's proposed demand charge for the Yukon hydro industrial class was expressed in terms of dollars per kV.A. The Board notes that the demands of both industrial customers in this zone are metered in kV.As and therefore finds NCPC's manner of expressing the demand charge to be appropriate.

8.3.5 Wholesale Rates

In its submission, NCPC proposed wholesale rates consisting of a single demand charge per kV.A designed to recover customer and demand costs, and a uniform energy charge designed to recover allocated energy costs.

Except as outlined below, the Board finds NCPC's method of designing wholesale rates to be reasonable.

8.3.5.1 NWT Diesel Rate Zone

NCPC indicated that its reference in cost allocation to certain of its NWT diesel customers as

"wholesale" customers may be misleading because they do not actually buy power from NCPC for subsequent distribution. These customers include Transport Canada and GNWT, who take power from NCPC at primary voltage. For rate design purposes, the rates for this class are referred to by NCPC as "primary service" rates.

During cross-examination, NCPC agreed that the customers in question could be thought of as commercial customers, with the differentiating characteristic being that they are served at primary voltage, whereas other commercial customers are served at a lower voltage.

The Board believes that, in the circumstances, the rates for the NWT diesel customers who have been identified in NCPC's cost allocation as "wholesale" customers should be structured similarly to the general service rates. The Board therefore recommends that the rates for these customers (i.e. primary service rates) be based on the appropriately allocated costs for the class, but that the rate structure consist of a single customer charge, a single demand charge, and a single energy charge (see Section 8.3.3). NCPC indicated that the demand of each of the customers in question is either metered or estimated by NCPC in terms of kWs. The Board therefore finds it appropriate to express the demand charge in terms of kWs for the test year.

8.3.6 Rates for Interruptible Service

In the Yukon hydro rate zone, NCPC provides energy on an interruptible basis to United Keno Hill Mines and the Whitehorse Hospital for electric boiler consumption. NCPC's proposed rates for interruptible service took the form of a single energy charge designed to recover energy costs. This charge reflected the fact that NCPC had allocated only energy-related costs to the interruptible service in its fully distributed cost of service study. The resulting proposed rate was 0.961¢ per kW.h, whereas NCPC's existing rates are 3.36¢ per kW.h for the Whitehorse Hospital and 2.478¢ per kW.h for United Keno Hill Mines. During the inquiry, NCPC indicated that the Commission's present interruptible service rates are based on value-of-service pricing rather than determined by a cost of service analysis.

In light of the marketing considerations of providing an interruptible service, i.e., the fact that electricity must compete with boiler fuel and that the competitiveness of electricity will vary from location to location or customer to customer within the same location, the Board recommends that NCPC continue to use a value-of-service pricing approach in determining suitable rates for its interruptible customers. The Board further recommends that the rates for the test year for interruptible service be those currently in effect, escalated by four percent. Accordingly, the Board recommends that the test year rates for Whitehorse Hospital and United Keno Hill Mines be set at 3.49¢ and 2.58¢ per kW.h respectively.

8.3.7 Customer-Specific Charges

After having assigned certain costs to specific customers in the cost allocation section of its submission, NCPC simply divided the annual costs assigned to these customers by 12 in order to arrive at specific charges per month for rate design purposes.

With the exception outlined in Section 8.3.7.1, the Board finds NCPC's calculation of specific monthly charges to be reasonable.

8.3.7.1 NWT Hydro Rate Zone - Pine Point Mines

As outlined in Section 8.1, NCPC has an agreement with Pine Point Mines to which is appended a payment schedule in respect of a 7.5 MW diesel plant. As set out in Section 7.3.4.3, the Board recommends that the payment as specified in the schedule for the test year be assigned to Pine Point Mines. Pine Point Mines pointed out in its evidence that the payment per the agreement was calculated assuming an interest rate of 9.734 percent, and that the payments would be made annually. Pine Point Mines expressed concern over NCPC's calculation of the monthly charge, stating that simply dividing the annual payment per the agreement by 12 to arrive at a monthly charge would effectively result in interest costs to the mine of more than 9.734 percent. During cross-examination, NCPC indicated that it would be amenable to receiving an annual payment.

Having recommended that the amount to be collected through a special charge to Pine Point Mines should be the annual payment which was stipulated in the agreement with NCPC, the Board is of the view that the frequency of payment used in the agreement to calculate the charge should be respected. The Board therefore recommends that the special charge to Pine Point Mines be assessed as an annual charge.

8.3.8 Rate Schedule Wording - Billing Demand

In its proposed general service, industrial and wholesale rate schedules, NCPC specified a ratchet demand provision whereby a customer's monthly billing demand is to be equal to the customer's maximum demand during the 12-month period ending with the current billing month. The minimum billing

demand for the general service rate was set at 5 kV.A. The Board notes that the ratchet demand provision is not new to NCPC's rate schedules, and that the provision does not presently apply to all of NCPC's industrial, wholesale and general service customers. However, the Board notes that no intervenor took issue with this provision.

8.3.9 Street Lighting Rates

In its submission, NCPC's proposed rates for street lighting consisted of a flat charge per month per luminaire, the charge depending on the size of luminaire. The Board notes that this type of rate structure is unchanged from NCPC's current structure for street lighting, and finds the method of designing rates for street lighting to be reasonable. However, the costs allocated by the Board to the street lighting class include all applicable costs and not only the incremental costs as proposed by NCPC (for details of the costs allocated to street lighting, see Section 7.4.2).

8.4 Rates for Heat Service

In its submission, NCPC's proposed heat rates consisted of a flat energy charge per million BTU.

The Board finds NCPC's method of designing rates for its heat service to be reasonable.

8.5 Rates for Water & Sewage Service

In its submission, NCPC's proposed water & sewerage rate consisted of: (1) a flat consumption charge per 1,000 imperial gallons (designed to fully recover fixed and variable costs, given the forecast consumption); and (2) a minimum monthly bill designed to ensure recovery of fixed costs each month.

During cross-examination, NCPC agreed that its rate design could result in over-recovery of fixed costs. A rate structure was proposed to NCPC which involved treating NCPC's minimum bill as a fixed monthly charge, and adjusting the consumption charge to recover only variable costs. NCPC stated that it viewed such a rate structure as being reasonable, and agreed that it reduced the possibility of over-recovery.

The Board therefore recommends that NCPC's water & sewerage rate consist of a fixed monthly charge designed to recover fixed costs and a consumption charge per 1,000 imperial gallons designed to recover variable costs.

8.6 Fuel Adjustment Clauses

During the inquiry, NCPC indicated that, about 1974/75, it introduced fuel adjustment clauses into its rate schedules. These clauses enabled NCPC to adjust its rates automatically as fuel prices varied from the levels that had been forecast when calculating the rates for the year. The Board notes that NCPC did not include fuel adjustment clauses in its proposed test year rate schedules.

During cross-examination, NCPC indicated that it had made use of fuel adjustment clauses in the past when fuel prices were fluctuating widely and were difficult to forecast with accuracy. NCPC explained that the relative stability in fuel prices experienced of late allowed NCPC to forecast average fuel prices for the year more accurately and it did not feel that a fuel adjustment clause was required for the test year.

The Board believes that a fuel adjustment clause protects all parties from the risk inherent in having to forecast fuel prices up to a year in advance. The Board also notes that if fuel prices unfold as anticipated and a rate adjustment for fuel is not required, no party is burdened by a utility having taken the precaution of including a fuel adjustment clause in its rate schedules.

The Board, therefore, recommends that, in order to minimize risks, NCPC incorporate into its rate schedules, for the test year, appropriate fuel adjustment clauses and that these clauses operate on a zone-wide basis.

8.7 Thermal Generation Adjustment Clauses

In the past, NCPC has incorporated into its hydro system rate schedules a thermal generation adjustment clause. This clause was designed to enable NCPC to increase (or decrease) its hydro system rates from month to month, to the extent that the actual amount of diesel fuel used deviated from the usage that had been forecast when setting the rates. The Board notes that NCPC did not include a provision for thermal generation rate adjustments in its proposed rate schedules.

During the inquiry, NCPC explained that for the purpose of its submission, it had assumed normal water flows for the hydro systems. NCPC acknowledged, however, that if normal water flows do not materialize, the Commission would feel obligated to approach its regulator and request an adjustment to the rates.

The Board is of the view that, if a rate adjustment is required, the mechanism to make the adjustment should be one which minimizes delays in reflecting the costs associated with the unanticipated changes in flow conditions. The Board considers that a thermal generation adjustment clause is such a mechanism, and that it would enable more timely ad-

justments to be made than if NCPC had to prepare submissions during the year for review and approval by its regulator.

The Board believes that NCPC should minimize the risks associated with forecasting fuel requirements in its hydro systems and recommends that, in the test year, NCPC incorporate suitable thermal generation adjustment clauses which operate on a zone-wide basis into its hydro rate zone rate schedules, and that any resulting surcharges (or credits) be shown separately on customers' bills. The Board also recommends, however, that, in order to reduce the need for making frequent adjustments of this nature and to promote smoothing of rates, consideration be given in the future to establishing a hydro rate stabilization fund.

8.8 Terms and Conditions of Service

These were not an issue during the inquiry and should therefore remain as heretofore.

Table 8-1

Yukon Hydro Rate Zone
Rates for the Test Year

Class	Proposed Monthly Charges Per Submission	NEB Recommended Monthly Charges
Residential	Customer Charge: $10.31 Energy Charge: 12.08¢/kW.h (0 - 700 kW.h) 10.08¢/kW.h (next 500 kW.h) 9.27¢/kW.h (all over 1 200 kW.h) Minimum Bill: $13.20	Customer Charge: $19.01 Energy Charge: 7.99¢/kW.h (Minimum Bill: the Customer Charge)
General Service	Small General Service: Demand Charge: $1.36/kV.A Energy Charge: 12.90¢/kW.h (0 - 900 kW.h) 10.89¢/kW.h (next 1 600 kW.h) 9.90¢/kW.h (all over 2 500 kW.h) Minimum Bill: the Demand Charge but not less than $14.58 Large General Service: Customer Charge: $11.04 Energy Charge: 14.21¢/kW.h (0 - 50 kW.h/kV.A) 9.90¢/kW.h (next 200 kW.h/kV.A) 9.79¢/kW.h (all over 250 kW.h/kV.A) Minimum Bill: $1.36/kV.A	Customer Charge: $19.08 Demand Charge: $13.90/kW or kV.A Energy Charge: 1.68¢/kW.h (Minimum Bill: the Customer and Demand Charge)
Wholesale	Demand Charge: $32.38/kV.A Energy Charge: 0.963¢/kW.h (Minimum Bill: the Demand Charge)	Demand Charge: $12.69/kV.A Energy Charge: 1.53¢/kW.h (Minimum Bill: the Demand Charge)
Industrial (Primary)	Demand Charge: $32.00/kV.A Energy Charge: 0.961¢/kW.h (Minimum Bill: the Demand Charge)	Demand Charge: $12.37/kV.A Energy Charge: 1.53¢/kW.h (Minimum Bill: the Demand Charge)
Industrial (Secondary)	Energy Charge: 0.961¢/kW.h	Whitehorse Hospital: Energy Charge: 3.49¢/kW.h United Keno Hill Mines: Energy Charge: 2.58¢/kW.h
Street Lights	$5.63/mo. per 125W luminaire $5.73/mo. per 175W luminaire	$10.44/mo. per 125W luminaire $10.71/mo. per 175W luminaire
Specific Charges - to Cyprus Anvil	$685.92/mo.	$20,684.25/mo.

Table 8-2

Yukon Diesel Rate Zone
Rates for the Test Year

Class	Proposed Monthly Charges Per Submission	NEB Recommended Monthly Charges
Residential	Customer Charge: $18.85 Energy Charge: 37.38¢/kW.h (0 - 700 kW.h) 28.51¢/kW.h (next 500 kW.h) 28.02¢/kW.h (all over 1 200 kW.h) Minimum Bill: $26.99	Customer Charge: $27.07 Energy Charge: 34.14¢/kW.h (Minimum Bill: the Customer Charge)
General Service	Small General Service: Demand Charge: $3.58/kV.A Energy Charge: 40.22¢/kW.h (0 - 900 kW.h) 38.23¢/kW.h (next 1 600 kW.h) 28.30¢/kW.h (all over 2 500 kW.h) Minimum Bill: the Demand Charge, but not less than $27.01 Large General Service: Customer Charge: $19.95 Energy Charge: 46.49¢/kW.h (0 - 50 kW.h/kV.A) 33.41¢/kW.h (next 200 kW.h/kV.A) 29.52¢/kW.h (all over 250 kW.h/kV.A) Minimum Bill: $3.58/kV.A	Customer Charge: $27.04 Demand Charge: $25.21/kW or kV.A Energy Charge: 19.97¢/kW.h (Minimum Bill: the Customer and Demand Charge)
Street Lights	$28.66/mo. per 175W luminaire $32.27/mo. per 250W luminaire	$35.92/mo. per 175W luminaire $40.32/mo. per 250W luminaire

Table 8-3

Field, B.C. Rate Zone
Rates for the Test Year

Class	Proposed Monthly Charges Per Submission	NEB Recommended Monthly Charges
Residential	Customer Charge: $12.78 Energy Charge: 31.80¢/kW.h (0 - 700 kW.h) 23.59¢/kW.h (next 500 kW.h) 23.37¢/kW.h (all over 1 200 kW.h) Minimum Bill: $18.23	Customer Charge: $19.29 Energy Charge: 30.07¢/kW.h (Minimum Bill: the Customer Charge)
General Service	Small General Service: Demand Charge: $1.98/kV.A Energy Charge: 34.12¢/kW.h (0 - 900 kW.h) 24.60¢/kW.h (next 1 600 kW.h) 23.59¢/kW.h (all over 2 500 kW.h) Minimum Bill: the Demand Charge, but not less than $18.18	Customer Charge: $19.26 Demand Charge: $30.75/kW or kV.A Energy Charge: 21.59¢/kW.h (Minimum Bill: the Customer and Demand Charge)
	Large General Service: Customer Charge: $10.73 Energy Charge: 32.84¢/kW.h (0 - 50 kW.h/kV.A) 26.75¢/kW.h (next 200 kW.h/kV.A) 23.91¢/kW.h (all over 250 kW.h/kV.A) Minimum Bill: $1.98/kV.A	
Street Lights	$26.35/mo. per 125W luminaire $29.17/mo. per 175W luminaire	$28.03/mo. per 125W luminaire $31.08/mo. per 175W luminaire

Table 8-4

NWT Hydro Rate Zone
Rates for the Test Year

Class	Proposed Monthly Charges Per Submission	NEB Recommended Monthly Charges[1]
Residential	Customer Charge: \$16.95 Energy Charge: 8.64¢/kW.h (0 - 700 kW.h) 6.63¢/kW.h (next 500 kW.h) 5.94¢/kW.h (all over 1 200 kW.h) Minimum Bill: \$22.34	Customer Charge: \$22.74 Energy Charge: 8.13¢/kW.h (Minimum Bill: the Customer Charge)
General Service	Small General Service: Demand Charge: \$3.53/kV.A Energy Charge: 9.38¢/kW.h (0 - 900 kW.h) 7.37¢/kW.h (next 1 600 kW.h) 6.38¢/kW.h (all over 2 500 kW.h) Minimum Bill: the Demand Charge, but not less than \$22.31 Large General Service: Customer Charge: \$16.63 Energy Charge: 12.74¢/kW.h (0 - 50 kW.h/kV.A) 7.05¢/kW.h (next 200 kW.h/kV.A) 5.40¢/kW.h (all over 250 kW.h/kV.A) Minimum Bill: \$3.53/kV.A	Customer Charge: \$22.73 Demand Charge: \$13.50/kW or kV.A Energy Charge: 2.41¢/kW.h (Minimum Bill: the Customer and Demand Charge)
Wholesale	Demand Charge: \$15.42/kV.A Energy Charge: 1.71¢/kW.h (Minimum Bill: the Demand Charge)	Demand Charge: \$11.47/kV.A Energy Charge: 2.17¢/kW.h (Minimum Bill: the Demand Charge)
Industrial (Primary)	Demand Charge: \$15.52/kV.A Energy Charge: 1.706¢/kW.h (Minimum Bill: the Demand Charge)	Demand Charge: \$11.57/kV.A[2] Energy Charge: 2.17¢/kW.h (Minimum Bill: the Demand Charge)
Street Lights	\$6.88/mo. per 125W luminaire \$7.89/mo. per 175W luminaire \$8.29/mo. per 250W luminaire \$9.59/mo. per 400W luminaire	\$ 9.24/mo. per 125W luminaire \$11.58/mo. per 175W luminaire \$12.40/mo. per 250W luminaire \$14.77/mo. per 400W luminaire
Specific Charges - To ICG Utilities: - To Pine Point Mines:	 \$585.83/mo. \$72,691.00/mo.	 \$523.33/mo. \$872,287.00/year
Specific Credits - To Con Mine:	 \$791.67/mo.	 \$791.67/mo.

1 With the exception of the specific charge to Pine Point Mines, which the Board recommends be an annual charge.

2 Equivalent charge per kW of demand for Pine Point Mines: \$12.18/kW.

Table 8-5

NWT Diesel Rate Zone
Rates for the Test Year

Class	Proposed Monthly Charges Per Submission	NEB Recommended Monthly Charges
Residential	Customer Charge: $18.00 Energy Charge: 42.59¢/kW.h (0 - 700 kW.h) 36.60¢/kW.h (next 500 kW.h) 32.81¢/kW.h (all over 1 200 kW.h) Minimum Bill: $26.14	Customer Charge: $27.55 Energy Charge: 38.88¢/kW.h (Minimum Bill: the Customer Charge)
General Service	Small General Service: Demand Charge: $3.73/kV.A Energy Charge: 47.27¢/kW.h (0 - 900 kW.h) 38.75¢/kW.h (next 1 600 kW.h) 34.93¢/kW.h (all over 2 500 kW.h) Minimum Bill: the Demand Charge, but not less than $26.17 Large General Service: Customer Charge: $22.36 Energy Charge: 48.85¢/kW.h (0 - 50 kW.h/kV.A) 38.94¢/kW.h (next 200 kW.h/kV.A) 35.15¢/kW.h (all over 250 kW.h/kV.A) Minimum Bill: $3.73/kV.A	Customer Charge: $27.59 Demand Charge: $25.02/kW or kV.A Energy Charge: 25.55¢/kW.h (Minimum Bill: the Customer and Demand Charge)
Primary Service ("Wholesale")	Demand Charge: $22.46/kV.A Energy Charge: 25.73¢/kW.h (Minimum Bill: the Demand Charge)	Customer Charge: $26.08 Demand Charge: $16.16/kW Energy Charge: 23.56¢/kW.h (Minimum Bill: the Customer and Demand Charge)
Industrial (Primary)	Demand Charge: $64.96/kV.A Energy Charge: 26.14¢/kW.h (Minimum Bill: the Demand Charge)	Demand Charge: $41.06/kW Energy Charge: 23.29¢/kW.h (Minimum Bill: the Demand Charge)
Street Lights	$25.67/mo. per 125W luminaire $28.67/mo. per 175W luminaire $32.70/mo. per 250W luminaire $38.11/mo. per 400W luminaire	$35.34/mo. per 125W luminaire $38.22/mo. per 175W luminaire $43.52/mo. per 250W luminaire $51.77/mo. per 400W luminaire

Table 8-6

Heat Service
Rates for the Test Year

Type of Service	Proposed Monthly Charges Per Submission	NEB Recommended Monthly Charges
Wholesale Heat (Frobisher Bay)	Energy Charge: $25.21 per million BTU	Energy Charge: $24.20 per million BTU
Retail Heat (Inuvik)	Energy Charge: $17.68 per million BTU	Energy Charge: $16.52 per million BTU

Table 8-7

Water and Sewage Service
Rates for the Test Year

Proposed Monthly Charges Per Submission	NEB Recommended Monthly Charges
Consumption Charge: $3.45 per 1000 imperial gallons water consumed per month Minimum Bill: $33.50 per month	Consumption Charge: $1.28 per 1000 imperial gallons water consumed per month Fixed Monthly Service Charge: $20.62 per month

Chapter 9
Regulation of NCPC in the Future

9.1 General

Currently, under the NCPC Act, the Commission is required to establish ranges of rates for each rate zone: Yukon and Northwest Territories being separate rate zones. These ranges are subject to the approval of the Governor in Council. The actual rates set and charged by NCPC must fall within these ranges and recover not less than the estimated cost of supplying the utility service in the rate zone. Under this arrangement, there is effectively no public input into the setting of rates for any particular location.

The Board continues to hold the view expressed in its August 1983 report that there is a need for an independent body to regulate NCPC's rates and that there should be public input into the setting of rates. In addition, major projects to be undertaken by NCPC should be reviewed and approved by the same independent regulatory body prior to construction being allowed to commence. This is particularly important because capital additions have a major and long-lasting impact on the revenue requirement, and hence the rates of a utility such as NCPC. In effect, if capital additions are not regulated, then rates are largely unregulated.

The Board notes that discussions are intended to take place on the possible transfer to the North of federal responsibility over NCPC. The Board remains of the view that, as long as the responsibility for NCPC rests with the federal government, the Commission should be regulated by a duly-appointed federal regulatory agency. Such agency should have, for the purposes of regulating NCPC's rates, representatives from the territories as did the Board for this inquiry. The Board is also of the opinion that, in the event of NCPC's devolution to the territories or its privatization, the regulation of the utility operations should be carried out by the respective territorial public utilities boards.

At present, NCPC is required to submit its annual capital and operating budgets to the Minister of Indian Affairs and Northern Development and to Treasury Board for approval. The Board continues to consider that having a regulatory agency review and approve the revenue requirement and the resultant rates of NCPC should eliminate the necessity of other government approvals of the capital and operating budgets.

9.2 Method of Regulation

The Board believes that to maximize the efficiency of the regulatory process, and hence of NCPC, it is important that any duly-appointed regulatory agency be given complete and final authority in establishing NCPC's annual revenue requirement for a given period, and in determining the associated cost-based rates. This would necessarily include the approval of NCPC's annual operating and capital expenditure budgets. Furthermore, any subsidization of electric power rates should be accomplished outside the regulatory process and, as a question of public policy, should be decided at the political level.

Under the above arrangement, NCPC would be required to submit its rate proposals in the form of an application to the regulatory agency. Such an application would be similar in form and content to the submission made by NCPC in this inquiry. Upon completion of its review and analysis of the application, the regulatory agency would approve a revenue requirement for NCPC and the associated cost-based rates for each rate zone. The decisions of the regulatory agency would be binding upon NCPC and would not be subject to ministerial override. The decisions should be open to review by the regulatory agency on any matter and open to appeal to the courts only on questions of law.

To ensure that all interested parties are given the opportunity to express their views on rate applications brought before the appointed regulatory agency, the Board recommends that public rate hearings be held in each territorial capital and at such other locations within the territories where the public interest so warrants.

The Board recognizes that the rates thus established would no doubt in many cases be more than the customers could afford to pay. The Board assumes that

the federal government would continue to determine the amount of subsidies and the method of providing them to the various classes or groups of customers in order to adjust, where needed, the amounts payable by the customers to more acceptable levels. In establishing such subsidies, the federal government may wish to receive input from the territorial governments or their public utilities boards.

9.3 Project Approval

During the inquiry, considerable concern was expressed by a number of interested parties about the manner in which NCPC proceeded with a number of projects.

For example, the evidence adduced during the inquiry raised a number of issues that cast doubt on the validity of the economic study which was used to justify the construction of Whitehorse No. 4. Had the proposal to construct Whitehorse No. 4 been subject to a public hearing before a duly-appointed regulatory agency, these issues could have been addressed in a more clearly impartial and independent manner, and the decision to proceed with Whitehorse No. 4, and under what conditions, could have been made on a more rigorous basis.

With respect to the extensions into the Bear Creek and Rock Creek subdivisions in Dawson, Yukon, it was established that NCPC proceeded with these projects without requiring the contributions in aid of construction called for by its own policy. While there may have been good reasons for disregarding the policy in these two cases, they were never established in a public forum prior to the extensions being built.

In view of these and other situations which came to light, the Board recommends that the Commission be required to submit an application to the duly-appointed regulatory agency in respect of each project involving a capital expenditure of $50,000 or more which NCPC proposes to develop. The regulatory agency would consider all aspects of each application. For projects involving capital expenditures of less than $5,000,000, the agency would of its own motion approve or deny the applied-for projects. For larger projects, the agency would either deny the application or recommend its approval to the Governor in Council. This recommended project approval process is similar to that which currently applies to pipelines regulated by the Board.

9.4 Changes to the NCPC Act

In order to facilitate the implementation of the recommendations made by the Board in this report, the NCPC Act must be amended. While the Board has not examined this matter in detail, the amendments that appear to be necessary include the repeal of Sections 10, 11, 12, 13, 27 and 28 of the NCPC Act. These sections should then be replaced, in the NCPC Act, by sections that require NCPC to:

1. charge only rates which have been approved by the duly-appointed regulatory agency;
2. have its capital and operating budgets approved by that same agency; and
3. apply to the agency for approval of each project involving a capital expenditure of $50,000 or more.

In addition, the NCPC Act should be amended so that the prescription and collection of fees, as set out in Section 25 of the Act, would be subject to the approval of the regulatory agency.

As well, Section 23 of the NCPC Act should be amended to recognize:

1. that NCPC's accounting system must be approved by and conform to the needs of the duly-appointed regulatory agency; and
2. that NCPC's accounts would be subject to audit by the duly-appointed regulatory agency.

Chapter 10
Other Matters

10.1 Agreement to Sell the Field, B.C. Plant

NCPC has operated a diesel generating plant at Field, B.C. since 1959.

On 26 January 1984, NCPC entered into a conditional agreement to sell its Field operation to Kicking Horse Hydro Development Limited with NCPC receiving a $100,000 deposit. The closing date of this agreement is 11 August 1985.

One of the conditions of this agreement is that the purchaser must have an operable hydro facility in place by 31 July 1985. During the inquiry, NCPC indicated that, because construction of the hydro facility had not yet commenced, it was doubtful that the sale would take place during the test year.

In light of this uncertainty, the Board recommends that for rate-making purposes in the test year, the $100,000 deposit be set up as a deferral in the books of accounts of NCPC. The ultimate disposal of this amount for rate-making purposes should be decided by the duly-appointed regulatory agency.

10.2 Nonelectric Utility Operations

NCPC provides heat, and water and sewage services at Inuvik and provides heat on a wholesale basis to the Government of the Northwest Territories at Frobisher Bay.

In its August 1983 report, the Board noted that NCPC was having difficulty providing some of these nonelectric services at prices economically attractive to the customers and that substantial financing would be required to refurbish much of the nonelectric utility plant at Inuvik.

In its August 1983 report, the Board recommended that the nonelectric utility business of NCPC at Inuvik be transferred to another agency. The Board believes that the same situation continues to exist regarding these nonelectric utility retail operations and again recommends that they be transferred to another agency.

The foregoing chapters set forth our findings and recommendations on matters relating to the Northern Canada Power Commission, pursuant to a request from the Minister of Indian Affairs and Northern Development to the Minister of Energy, Mines and Resources.

J.R. Hardie
Presiding Member

W.G. Stewart
Member

E.S. Bell
Member

J.M. Heath
Member

R.A. Laking
Member

Ottawa, Canada
June 1985

Background information

1.0 History of Northern Canada Power Commission

The Northwest Territories Power Commission was created as an agency of the Government of Canada in 1948 to operate a single hydroelectric plant on the Snare River near Yellowknife, Northwest Territories. In 1956, the name of the organization was changed to Northern Canada Power Commission. NCPC gradually took over the operation of generating facilities built by others and undertook the construction and operation of electrical utility systems at various additional sites. Now, NCPC owns and operates facilities at 59 locations throughout Yukon and the Northwest Territories in a service area which covers all Canadian territory north of the 60th parallel, except in Quebec and Labrador, and includes numerous communities separated by vast distances. NCPC's only operation outside of the territories is in Yoho National Park, where it has supplied electricity to the community of Field, British Columbia since 1959 following a request from the Park to consolidate power facilities in the Park previously owned and operated by the Park and Canadian Pacific Railway.

NCPC's facilities include hydroelectric and diesel generation plants, five transmission systems and numerous isolated electrical distribution systems. Many of the facilities were originally installed by other agencies to serve their particular needs and were transferred to NCPC over the years. Some facilities have been developed to serve isolated mining operations and the associated communities so that a single customer may utilize a large portion of a particular power station's output. In such locations, the economics of the utility service are thus heavily dependent on the business of one customer.

While NCPC distributes electricity to the ultimate consumer in most locations, it supplies power on a wholesale basis to two investor-owned companies, the Yukon Electrical Company Limited and ICG Utilities (Plains-Western) Ltd., for distribution in parts of Yukon and the Northwest Territories respectively. In addition, NCPC supplies heat, and water and sewage services in Inuvik, provides wholesale heat supply in Frobisher Bay and makes residual heat available in various other locations. It also provides minor services under contract.

2.0 Northern Canada Power Commission Act

The NCPC Act, as amended, established the utility as a Crown corporation which is empowered to supply electric power and other public utilities in northern Canada. NCPC is accountable to Parliament through the Minister of Indian Affairs and Northern Development. The Act does not preclude other private corporations and other government agencies from supplying power to communities North of 60°.

The Commission consists of a chairman and four members, all of whom are appointed by the Governor in Council and hold office during pleasure. Two of these members are appointed, one each, on the recommendation of the Commissioner in Council of the Northwest Territories and of Yukon.

Under the terms of its enabling legislation, NCPC as an agent of Her Majesty may acquire and maintain plants within the Northwest Territories and Yukon, and with the approval of the Governor in Council, elsewhere in Canada subject to the laws of the province in which the powers are exercised.

Subject to the approval of the Governor in Council, NCPC is required to set ranges of rates for its services applicable to each zone in which it operates; Yukon and the Northwest Territories being separate rate zones within the meaning of the NCPC Act. Such rates are required to recover not less than the estimated cost of supplying the public utility service in the rate zone. These costs must include all operating, maintenance and administration costs as well as payments of interest and principal in respect of loans, and a provision for contingencies currently set by Order in Council at four percent of annual sales.

The Minister of Finance may authorize payment to NCPC of $50,000 from the Consolidated Revenue

Fund for the purpose of funding investigations of new electrical generation projects. If a project is constructed, the cost of such investigation is charged to the capital cost of the facility. If a project does not proceed, the cost of the initial investigation is written off as a budgetary charge of the federal government.

Loans to the Commission for capital expenditures may be authorized by the Minister of Finance, on terms and conditions approved by the Governor in Council, from Parliamentary appropriations provided specifically for that purpose. In addition, with the approval of the Governor in Council and on terms and conditions approved by him, the Minister of Finance may authorize loans of up to one million dollars at a time out of the Consolidated Revenue Fund, such loans being submitted to Parliament for approval in the estimates of the following fiscal year.

All accounts of NCPC are subject to audit by the Auditor General of Canada.

3.0 Northern Canada Power Commission Operations

NCPC is an unusual electric utility in that it is comprised of over 50 separate power systems serving populations of some 23,000 located in an area of 536 000 square kilometres in Yukon and 46,000 located in an area of 3 245 000 square kilometres in the Northwest Territories. The two major communities are the cities of Whitehorse, Yukon and Yellowknife, NWT. There is some concentration of population in southern Yukon and along the Mackenzie River Valley in the Northwest Territories, but most other communities are small and scattered. The net peak load in the fiscal year 1983/84 was about 126 MW and sales were 580.5 GW.h, down 5.7 percent from the previous year's total of 615.9 GW.h. The separate power systems have generating capacities ranging from 80 MW in the Whitehorse area to 61 kW at Jean Marie River in the Northwest Territories. The total installed capacity as of 31 March 1984 was approximately 267 MW. Each of the power systems must be planned and operated independently.

Hydro generation exists in Mayo and in the Whitehorse-Aishihik- Faro area, both in southern Yukon, and in the Great Slave Lake region in the Northwest Territories. Diesel generators are used in all other locations. The larger systems having hydroelectric plants and the diesel systems in regional centres have full-time staff but many of the smaller stations are operated by local part-time operators. The skilled linemen, maintenance men and operators at the regional centres travel to the smaller plants as required to supplement the work of local part-time operators. For major maintenance of machinery and equipment, this staff is supplemented when necessary by representatives of the manufacturers.

In the larger diesel plants, the staff have the necessary skills to run two or more generators in parallel but in the smaller plants only one generator is used at any one time. For the best fuel economy, a larger unit is used to supply loads in the winter, while a smaller unit is used to meet summer loads. In this way the diesel engines can be run at or close to full load, which is the most efficient level, at all times. Additional diesel capacity is installed to provide reserve capacity to deal with breakdowns and to allow for routine maintenance. Regular maintenance schedules are planned on the basis of the number of hours the units have run. This situation leads to a wide variation from year to year in maintenance work and associated costs at each station.

The criterion used for determining the size of a new unit to add capacity at a diesel station is the forecast of load growth for the next five years, thereby offering the probability of fewer changes and greater economy in the long-run. Because electricity is a necessity of life in the North, each plant system is designed to provide at least 99 percent reliability. In addition, a gas turbine powered generator is held as spare in Edmonton and can be flown by Hercules aircraft to any station in an emergency. Reserve levels are much higher than in southern electric utilities but this situation is, in general, unavoidable given the isolation of the stations from each other, the operating difficulties with some semi-skilled staff and the need to provide secure service.

4.0 Territorial Regulation of Electric Utilities

The government of each territory has established an administrative board to regulate the activities of electric utilities in the territory. The Yukon Utilities Board and the Public Utilities Board of the Northwest Territories are similar in organization, jurisdiction and powers.

Under the respective ordinances, an electric utility must obtain a franchise from a municipality or from the Commissioner of the territory. These franchises cannot be granted, renewed, or altered without the approval of the territorial public utilities boards. Complaints from the Commissioner, a municipality, or from a specified number of residents of a service area concerning the rates charged by the utility or a proposed increase in those rates, the service provided by the utility, or the areas to which the utility provides service, are adjudicated by the territorial boards. The territorial boards are empowered to

determine the rates to be charged, the conditions and manner in which the utility supplies electricity, and to order any reasonable extension of the facilities of the utility.

The territorial boards must conduct public hearings in the exercise of their powers, with the exception of the approval of franchises by the Yukon Utilities Board. Their decisions are final and binding.

As an agent of the federal government, NCPC is not legally subject to regulation by the territorial boards. In an attempt to address concerns regarding the lack of accountability to its customers, NCPC, from 1976 to 1983, voluntarily submitted its proposed rate increases to the territorial boards. The experience did not prove entirely satisfactory to the territories, because NCPC declined to implement certain recommendations of the territorial boards on the grounds that to do so would entail a conflict with NCPC's governing legislation. NCPC had also been criticized by the Auditor General for subjecting itself to such reviews.

Summary of Major Recommendations from the August 1983 Report of the NEB

The major recommendations proposed by the Board in its August 1983 report are summarized below. A number of subsidiary recommendations appear in the body of that report. In making these recommendations, the Board recognized that some of them would require federal legislation, including amendments to the NCPC Act.

A. Corporate Structure and Operations

1. NCPC should continue to operate as a single entity owned by the federal government.
2. A corporate form should be found for NCPC which leaves it as a federal crown agency but freed of some of the constraints which now inhibit business-like practices.
3. The head office of NCPC should remain in Edmonton.
4. In considering future appointments to the Commission, persons with expertise in the management of electric utilities should be sought.
5. The practice of recovering the waste heat from NCPC's diesel generators should be continued and extended provided the necessary facilities are installed and operated at no net cost to NCPC.
6. The nonelectric utility business of NCPC at Inuvik should be transferred to another agency.
7. The electric utility operations at Field, British Columbia should be taken over by others capable of accepting this responsibility.

B. Framework for Regulation

1. The regulation of NCPC, including the approval of rates and of the public convenience and necessity of major capital additions, should be assigned to a single federal regulatory agency.
2. The federal regulatory agency should be given complete and final authority in establishing NCPC's annual revenue requirements and in determining the cost-based rates associated therewith.
3. NCPC's rates should be established by the federal regulatory agency following rate hearings with opportunity for participation by all affected parties.
4. These rate hearings should be held in each territorial capital. Consideration should also be given to holding public hearings in other locations throughout the territories, wherever warranted by public interest.

C. Revenue Requirements

1. NCPC's revenue requirement should be determined using the rate base/rate of return method.
2. NCPC should be required to physically inventory all of its fixed assets, identifying those that are presently in use and those which can reasonably be expected to be used in the future. NCPC's revenue requirement should not reflect costs associated with assets from which its customers no longer derive any benefit.
3. NCPC should undertake a depreciation study to determine the physical and economic lives of its assets, and should calculate depreciation expense for all of its assets on a straight-line basis over the shorter of the physical or economic life of the assets.
4. NCPC's operating and maintenance expenses should henceforth be subject to public scrutiny at rate hearings.

D. Capitalization

1. The appropriate method for creating the necessary equity capital in NCPC's capital structure is through the conversion of some of the present debt to equity, and, if necessary, through the direct injection of equity capital.
2. The debt amounting to $9.2 million, which exists because of prior losses, should be forgiven.

3. The working capital loan of $7.5 million should be converted to equity.
4. Outstanding loans, incurred in respect of assets which are no longer "used and useful", should be forgiven.
5. Rate of return matters should be dealt with in a rate hearing held by the agency charged with regulating NCPC.

E. Approval and Funding of Major Projects

1. In respect of each project which it proposes to develop, NCPC should be required to submit an application to the regulatory agency which would consider all aspects of the application and make its recommendation to the Governor in Council.
2. Project studies should be financed by way of provisions included in the cost of service approved by the regulatory agency, or, in the case of large expenditures, by funding from the federal treasury, upon the recommendation of the regulatory agency.
3. There should be an agreement between NCPC and the federal government guaranteeing financial arrangements to allow hydroelectric projects which are economical in the long term to be developed without risk to northern residents, and the proposed federal regulatory agency should consider such financial provisions at the project approval stage.

F. Rate Design

1. NCPC's rates should generally be based on cost.
2. In each of the territories, there should be two rate zones: a hydro rate zone and a diesel rate zone.
3. Government and nongovernment classifications in the rate structure should be eliminated.
4. The proposed federal regulatory agency should consider the following additional issues relating to rates:
   (a) a reduction in the number of blocks in the rate structure;
   (b) the need for life-line rates in the North; and
   (c) the possibility of the establishment of a hydro stabilization fund.
5. Any subsidization of electric power rates should be accomplished outside the regulatory process.

ORDER NO. EHR-1-84

IN THE MATTER OF the National Energy Board Act and subsections 22(2) and 20(3) thereof; and

IN THE MATTER OF an inquiry into matters relating to the Northern Canada Power Commission under File No. 1970-3/N28-1

BEFORE the Board on Thursday, 28 June 1984.

WHEREAS under the Northern Canada Power Commission Act the Northern Canada Power Commission ("NCPC") is required to establish schedules or ranges of rates for public utilities supplied by it in the Yukon and Northwest Territories; and

WHEREAS the schedules and ranges of rates established by the Commission are subject to the approval of the Governor in Council; and

WHEREAS the Minister of Energy, Mines and Resources, at the request of the Minister of Indian and Northern Affairs, has by letter dated 4 April 1984 asked the National Energy Board ("the Board") pursuant to subsection 22(2) of the National Energy Board Act to inquire into and report on the revenues of the NCPC and the determination of cost based rates which may be charged by NCPC from 1 April 1985 to 31 March 1986 inclusive; and

WHEREAS the Board finds it advisable to hold a public inquiry to afford an opportunity for interested parties to be heard.

IT IS ORDERED THAT:

Inquiry

1. The Board, through a five member Panel which will include a Temporary Member from each of the Northwest Territories and the Yukon, will hold a public inquiry in the Northwest Territories and the Yukon at the following dates and locations:

(a)	Whitehorse, Y.T. Hotel Sheffield Village Square 1 & 2	19 November to 23 November 1984
(b)	Yellowknife, N.W.T. Explorer Hotel Katimavik Room	26 November to 29 November 1984
(c)	Whitehorse, Y.T. Hotel Sheffield Village Square 1 & 2	7 January 1985 Until the Evidence related to the Yukon is completed
(d)	Yellowknife, N.W.T. Explorer Hotel Katimavik Room	In January 1985 at dates to be announced later

2. The subject matters of the inquiry are outlined in Appendix I to this Order.

3. NCPC shall, on or before 19 October 1984 file with the Board 25 copies of:

   (a) a submission setting out its proposed rate base, revenue requirement, rate zones and rate design for the year 1 April 1985 to 31 March 1986; and

   (b) for each witness that NCPC intends to present at the inquiry, the written evidence of that witness, in question and answer form with lines numbered.

NCPC shall also deliver one copy of the submission and of the written evidence to each individual intervenor who states in his Notice of Intention to Participate (see Paragraph 8) that he wishes to receive a copy, and to each intervenor referred to in Paragraph 9, and NCPC shall also make available for public inspection at each NCPC location listed in Paragraph 15 two copies of the submission and written evidence.

4. To expedite the hearing process, principal examination of subject matters will be conducted in the following order at each location:

   (a) Whitehorse - electric utility rate base, revenue requirement, including determination and allocation of head and regional office costs, and rate design for those rate zones within the Yukon Territory; and

(b) Yellowknife - rate base, revenue requirement including determination and allocation of head and regional office costs, and rate design for
   (i) electric utility rate zones in the Northwest Territories,
   (ii) electric utility operations in Field, British Columbia, and
   (iii) nonelectric utility rate zones in the Northwest Territories.

5. At the sittings to be held in November 1984, the evidence shall be heard in the following order:

   (a) Electric Utility Rate Base, Item (1) of Appendix I and then, if time permits;
   (b) Electric Utility Revenue Requirement, Item (2) of Appendix I; and
   (c) In no event will the Board hear evidence on electric utility rate design or NCPC's nonelectric utility operations during the November sittings.

In November, the Board intends, before proceeding with other matters, to hear all of the evidence on rate base. The Board will first hear all of the evidence of NCPC on rate base and will then hear all of the evidence of each intervenor in turn on rate base matters. The Board will then start to hear NCPC's evidence on revenue requirement.

6. When the inquiry resumes in January, the Board will:

   (a) first deal with any of the electric utility rate base and revenue requirement matters not heard during November, then
   (b) hear evidence on electric utility rate zones and rate design, and finally
   (c) deal with matters relating to NCPC's nonelectric utility operations.

In January, the Board intends to hear, first, all of the remainder of NCPC's evidence before hearing the remaining evidence of each intervenor in turn.

Notice of intention to participate

Upon completion of the evidence on all items referred to in Appendix I, any party will have the right to make a final submission in Yellowknife either orally or in writing. The timing of such final submission will be announced at a later date.

7. For the purpose of the inquiry, the Board will adopt as the base year the period 1 April 1983 to 31 March 1984 and as the forward test year the period 1 April 1985 to 31 March 1986.

8. Any private individual who wishes to participate in the inquiry shall on or before 17 September 1984, unless otherwise authorized by the Board, send to the Secretary of the Board and to the Edmonton Office of NCPC a letter in English or French (known as a Notice of Intention to Participate) stating:

   (a) the individual's name, address, and telephone number;
   (b) the parts of the inquiry listed in Appendix I to this Order on which he wishes to make a presentation to the Board;
   (c) whether he wishes to receive a copy of NCPC's submission and written evidence;
   (d) whether he will attend the inquiry in Whitehorse or Yellowknife, and whether he wishes to speak English or French. Anyone who wishes to speak a language other than English or French must provide his own interpreter.

9. Any person or organization other than one referred to in Paragraph 8 that wishes to participate in the inquiry shall, unless otherwise authorized by the Board:

   (a) on or before 17 September 1984 file with the Secretary of the Board 25 copies, and deliver to each office of NCPC listed in Paragraph 15, one copy of a Notice of Intention to Participate containing the information set out in Sub-paragraphs 8(a), (b), (c) and (d); and
   (b) on receipt of a list of intervenors to be provided by the Board, as soon as possible send one copy of his Notice of Intention to Participate to each party named in the list.

Direct evidence

10. Any intervenor referred to in Paragraph 9 who wishes to adduce direct evidence in the inquiry shall, unless otherwise authorized by the Board, prepare direct evidence written in question and answer form with lines numbered and shall:

   (a) on or before 7 November 1984 for evidence on all matters, except electric utility rate zones and rate design and nonelectric utility matters, and

   (b) on or before 7 December 1984 for evidence on electric utility rate zones and rate design and nonelectric utility matters,

   file 25 copies thereof with the Secretary of the Board, and deliver one copy of the same to each NCPC location listed in Paragraph 15 and to any intervenor who pursuant to Sub-paragraph 8(b)

requested a copy of NCPC's submission and written evidence and to all intervenors referred to in Paragraph 9. Individual intervenors referred to in Paragraph 8 need not file written direct evidence.

Information requests

11. Where NCPC or an intervenor wishes to obtain additional information from another party to these proceedings in respect of matters raised in a filing made with the Board, such requests shall be made in writing, and the party to whom the request is made shall, as soon as possible, either provide a written response to the request or refer the question to the Board under Paragraph 12 or 13 hereof. Both written requests and the responses thereto shall be filed as exhibits at the hearing by the party responding to the request.

General

12. If any question arises upon which the decision of the Board may be required, one copy of a Notice of Motion with respect thereto shall be filed with the Secretary of the Board, one copy sent to each NCPC location listed in Paragraph 15, and one copy sent to each intervenor who might be affected, and the motion shall be heard by the Board at a date to be fixed by it.

13. Any party who is required by an Order of the Board to send documents to other parties, and who feels that this requirement would create an undue burden on him, may apply to the Board for permission not to send the documents. If the Board grants permission, the party shall provide the Board with the number of copies of the documents that the Board requests, and those copies will be available for public examination at the offices of the Board and with the Court Clerk during the inquiry. The party shall also make these documents available at such locations and in such number of copies as the Board may direct.

14. Procedural Orders will be issued by the Board with respect to the conduct of the inquiry.

15. Any interested party may examine a copy of all filings made pursuant to this Order at the following locations:

Library,
National Energy Board
Trebla Building 9th Floor
473 Albert Street
Ottawa, Ontario
K1A 0E5

Northern Canada Power Commission
7909 51st Avenue
P.O. Box 5700, Station "L"
Edmonton, Alberta
T6C 4J8

Northern Canada Power Commission
NWT Regional Office
Laurentian Building
P.O. Box 1860
Yellowknife, NWT
X1A 2PA

Northern Canada Power Commission
Yukon Regional Office
31 Federal Building
P.O. Box 4278
Whitehorse, Yukon Territory
Y1A 1H8

NATIONAL ENERGY BOARD

G. Yorke Slader
Secretary

APPENDIX I of
Order No. EHR-1-84

NCPC - Subject matters of the Inquiry

For electric utility operations within each of the Northwest and Yukon Territories and Field, B.C.:

1. For each rate zone, rate base for the base year and test year including the following items:
   (a) the original cost to NCPC of plant and equipment presently used and useful;
   (b) the accumulated depreciation as of the end of the base year and the beginning and end of the test year based on the straight line basis using expected useful life of the various classes of assets. The Board would be willing to consider methods of depreciation of assets other than straight line over useful life, but the NCPC is required to file details of accumulated depreciation on the straight line basis;
   (c) proposed plant additions and retirements from the end of the base year to the end of the test year; and
   (d) items, other than plant, to be included in rate base.

2. For each rate zone, revenue requirement for the test year and the determination thereof explaining any variances between the projected test year costs and the actual costs incurred in the base year, including but not limited to the following cost of service items:
   - operation and maintenance expenses;
   - fuel costs;
   - engineering and general administration expenses;
   - depreciation and depreciation rates;
   - return on rate base (which for the purposes of this inquiry shall be the cost of debt related to used and useful assets);
   - cost of other debt as required; and
   - allocation of head and regional office costs.

3. Rate Design for the test year: NCPC is required to file a rate design based on the recommendation set out in section 4.4 of the Board's report dated August 1983. That is, that in each of the territories there will be two rate zones: a hydro rate zone and a diesel rate zone. NCPC and any intervenors are free to advocate, in writing, other rate zone or rate design proposals, but any proposal must be accompanied by explanation and reasons justifying its consideration.

For nonelectric utility operations:

1. Rate base for the base year and test year.
2. Revenue requirement for the test year.
3. Rate design for the test year.

Appendix D

ORDER NO. AO-I-EHR-1-84

IN THE MATTER OF THE National Energy Board Act and subsections 22(2) and 20(3) thereof; and

IN THE MATTER OF an inquiry into matters relating to the Northern Canada Power Commission under File No. I970-3/N28-1

BEFORE the Board on Wednesday, 10 October 1984.

WHEREAS under the Northern Canada Power Commission Act the Northern Canada Power Commission ("NCPC") is required to establish schedules or ranges of rates for public utilities supplied by it in the Yukon and Northwest Territories; and

WHEREAS the schedule and ranges of rates established by the Commission are subject to the approval of the Governor in Council; and

WHEREAS THE Minister of Energy, Mines and Resources, at the request of the Minister of Indian and Northern Affairs, has by letter dated 4 April I984 asked the National Energy Board ("the Board"), pursuant to subsection 22(2) of the National Energy Board Act to inquire into and report on the revenues of the NCPC and the determination of cost based rates which may be charged by NCPC from 1 April 1985 to 31 March 1986 inclusive; and

WHEREAS the Board finds it advisable to hold a public inquiry to afford an opportunity for interested parties to be heard; and

WHEREAS the Board has considered an adjournment of the commencement date of the within hearing;

IT IS ORDERED THAT:

1. Sections 1, 5, 6 and 10 of Order No. EHR-1-84 are revoked and the following substituted therefor:

   1. The Board, through a five member Panel which will include a Temporary Member from each of the Northwest Territories and the Yukon, will hold a public inquiry in the Northwest Territories and the Yukon, at Yellowknife, N.W.T. and Whitehorse, Y.T., upon dates to be announced.

   5. At each location, the Board will first hear all of the evidence of NCPC on each of the matters referred to in Appendix 1 and will then hear all of the evidence of each intervenor in turn.

   6. Upon completion of the evidence on all items referred to in Appendix I, any party will have the right to make a final submission in Yellowknife either orally or in writing. The timing of such final submission will be announced at a later date.

   10. Any intervenor referred to in Paragraph 9 who wishes to adduce direct evidence in the inquiry shall, unless otherwise authorized by the Board, prepare direct evidence written in question and answer form with lines numbered and, on or before 7 December 1984, shall file 25 copies thereof with the Secretary of the Board, and deliver one copy of the same to each NCPC location listed in Paragraph 15 and to any intervenor who pursuant to Sub-paragraph 8(b) requested a copy of NCPC's submission and written evidence and to all intervenors referred to in Paragraph 9. Individual intervenors referred to in Paragraph 8 need not file written direct evidence.

NATIONAL ENERGY BOARD

G. Yorke Slader
Secretary

Appendix E

ORDER NO. AO-2-EHR-1-84

IN THE MATTER OF the National Energy Board Act and subsections 22(2) and 20(3) thereof; and

IN THE MATTER OF an inquiry into matters relating to the Northern Canada Power Commission under File No. 1970-3/N-28-1.

B E F O R E the Board on 27 December, 1984.

Whereas under the Northern Canada Power Commission Act, the Northern Canada Power Commission ("NCPC") is required to establish schedules or ranges of rates for public utilities supplied by it in the Yukon and Northwest Territories and which are subject to the approval of the Governor in Council; and

WHEREAS the Minister of Energy, Mines and Resources, with the agreement of the Minister of Indian and Northern Affairs, has by letter dated 21 December 1984 confirmed that the National Energy Board ("the Board") should proceed with hearings to examine the NCPC rate structures; and

WHEREAS the Board has indicated that it planned on conducting the NCPC inquiry by a panel of five Board Members including two temporary Members from the Yukon and Northwest Territories and such temporary Members have now been appointed; and

WHEREAS the Board finds it advisable to commence the public inquiry as soon as possible.

IT IS ORDERED THAT:

1. Sections 1 and 10 of Order No. EHR-1-84 as replaced by Section 1 of order No. AO-1-EHR-1-84, are revoked and the following substituted therefor:
   1. The Board, through a five Member Panel which includes a Temporary Member from each of the Northwest Territories and the Yukon, will hold a public inquiry in the Northwest Territories and the Yukon, at Yellowknife, N.W.T. and Whitehorse, Y.T. commencing at the following locations, dates and times:

(a) Whitehorse, Y.T. Hotel Sheffield Village Square 1 & 2 — 4 February 1985, 1:00 P.M. (local time)

(b) Yellowknife, N.W.T., Explorer Hotel Katimavik Room A & B — 4 March 1985, 1:00 P.M. (local time)

The Panel would be prepared to sit on Saturdays, 9 February and 9 March 1985, if the inquiry extends beyond five days at each location.

10. Any intervenor referred to in Paragraph 9 who wishes to adduce direct evidence in the inquiry shall, unless otherwise authorized by the Board, prepare direct evidence written in question and answer form with lines numbered and, on or before 7 January 1985, shall file 25 copies thereof with the Secretary of the Board, and deliver one copy of the same to each NCPC location listed in Paragraph 15 and to any intervenor who pursuant to sub-paragraph 8(b) requested a copy of NCPC's submission and written evidence and to all intervenors referred to in Paragraph 9. Individual intervenors referred to in Paragraph 8 need not file written direct evidence.

NATIONAL ENERGY BOARD,

G. Yorke Slader,
Secretary

Details of Adjustments to Test Year Rate Base

Tables F-1 to F-20 summarize the adjustments recommended by the Board to the rate base for each cost centre or rate zone. The rate base is comprised of:

1. the average of the opening and closing balances of net plant in service, and
2. an allowance for working capital.

Tables F-21 to F-29 provide details of the adjustments made by the Board to the test year rate bases.

Table F-1

Head Office Cost Centre
Test Year Rate Base Summary
($000)

	Per Submission	NEB Adjustments	NEB Recommended
Plant in Service	2,275	—	2,275
Less: Accumulated Depreciation	983	—	983
Net Plant in Service	1,292	—	1,292
Allowance for Working Capital[1]	820	227	1,047
Rate Base	**2,112**	**227**	**2,339**

1 Refer to Table F-2

Table F-2

Head Office Cost Centre
Determination of Test Year
Allowance for Working Capital
($000)

	Per Submission	NEB Adjustments	NEB Recommended
Net Cost of Service	4,969	517	5,486
Less: Depreciation	102	—	102
Cash Cost of Service	**4,867**	**517**	**5,384**
Cash Working Capital $4,867 x (25.425/365)	339	(339)	—
Cash Working Capital $5,384 x (31.59/365)[1]	—	466	466
Operating Materials & Supplies Inventory	383	100[2]	483
Prepaid Expenses	98	—	98
Allowance for Working Capital	**820**	**227**	**1,047**

1 Refer to Section 4.12.1
2 Refer to Section 4.8

Table F-3

Yukon Regional Office Cost Centre
Test Year Rate Base Summary
($000)

	Per Submission	NEB Adjustments	NEB Recommended
Plant in Service	55	—	55
Less: Accumulated Depreciation	31	—	31
Net Plant in Service	24	—	24
Allowance for Working Capital[1]	28	7	35
Rate Base	**52**	**7**	**59**

1 Refer to Table F-4

Table F-4

Yukon Regional Office Cost Centre Determination of Test Year Allowance for Working Capital ($000)

	Per Submission	NEB Adjustments	NEB Recommended
Net Cost of Service	405	(3)	402
Less: Depreciation	2	—	2
Cash Cost of Service	**403**	**(3)**	**400**
Cash Working Capital $403 x (25.425/365)	28	(28)	—
Cash Working Capital $400 x (31.59/365)[1]	—	35	35
Operating Materials & Supplies Inventory	—	—	—
Prepaid Expenses	—	—	—
Allowance for Working Capital	**28**	**7**	**35**

1 Refer to Section 4.12.1

Table F-5

Yukon Hydro Rate Zone Test Year Rate Base Summary ($000)

	Per Submission	NEB Adjustments	NEB Recommended
Plant in Service[1]	143,169	(73,951)	69,218
Less: Accumulated Depreciation[2]	35,669	(6,339)	29,330
Net Plant in Service	107,500	(67,612)	39,888
Allowance for Working Capital[3]	939	(19)	920
Rate Base	**108,439**	**(67,631)**	**40,808**

1 Refer to Table F-21
2 Refer to Table F-21
3 Refer to Table F-6

Table F-6

**Yukon Hydro Rate Zone
Determination of Test Year
Allowance for Working Capital
($000)**

	Per Submission	NEB Adjustments	NEB Recommended
Net Cost of Service	7,998	(885)	7,113
Less: Depreciation	4,228	(826)	3,402
Cash Cost of Service	**3,770**	**(59)**	**3,711**
Cash Working Capital $3,770 x (25.425/365)	263	(263)	—
Cash Working Capital $3,711 x (31.59/365)[1]	—	321	321
Operating Materials & Supplies Inventory	676	(77)[2]	599
Prepaid Expenses	—	—	—
Allowance for Working Capital	**939**	**(19)**	**920**

1 Refer to Section 4.12.1
2 Refer to Section 4.12.2

Table F-7

**Yukon Diesel Rate Zone
Test Year Rate Base Summary
($000)**

	Per Submission	NEB Adjustments	NEB Recommended
Plant in Service[1]	3,113	(60)	3,053
Less: Accumulated Depreciation	904	—	904
Net Plant in Service	2,209	(60)	2,149
Allowance for Working Capital[2]	204	28	232
Rate Base	**2,413**	**(32)**	**2,381**

1 Refer to Table F-22
2 Refer to Table F-8

Table F-8

**Yukon Diesel Rate Zone
Determination of Test Year
Allowance for Working Capital
($000)**

	Per Submission	NEB Adjustments	NEB Recommended
Net Cost of Service	1,830	(10)	1,820
Less: Depreciation	143	—	143
Cash Cost of Service	**1,687**	**(10)**	**1,677**
Cash Working Capital $1,687 x (25.425/365)	117	(117)	—
Cash Working Capital $1,677 X (31.59/365)[1]	—	145	145
Operating Materials & Supplies Inventory	87	—	87
Prepaid Expenses	—	—	—
Allowance for Working Capital	**204**	**28**	**232**

1 Refer to Section 4.12.1

Table F-9

**Field, B.C. Rate Zone
Test Year Rate Base Summary
($000)**

	Per Submission	NEB Adjustments	NEB Recommended
Plant in Service	276	—	276
Less: Accumulated Depreciation	250	—	250
Net Plant in Service	26	—	26
Allowance for Working Capital[1]	33	5	38
Rate Base	**59**	**5**	**64**

1 Refer to Table F-10

Table F-10

Field, B.C. Rate Zone
Determination of Test Year
Allowance for Working Capital
($000)

	Per Submission	NEB Adjustments	NEB Recommended
Net Cost of Service	318	(4)	314
Less: Depreciation	2	—	2
Cash Cost of Service	**316**	**(4)**	**312**
Cash Working Capital $316 x (25.425/365)	22	(22)	—
Cash Working Capital $312 x (31.59/365)[1]	—	27	27
Operating Materials & Supplies Inventory	11	—	11
Prepaid Expenses	—	—	—
Allowance for Working Capital	**33**	**5**	**38**

1 Refer to Section 4.12.1

Table F-11

NWT Regional Office Cost Centre
Test Year Rate Base Summary
($000)

	Per Submission	NEB Adjustments	NEB Recommended
Plant in Service[1]	199	(100)	99
Less: Accumulated Depreciation[2]	47	(4)	43
Net Plant in Service	152	(96)	56
Allowance for Working Capital[3]	21	3	24
Rate Base	**173**	**(93)**	**80**

1 Refer to Table F-23
2 Refer to Table F-23
3 Refer to Table F-12

Table F-12

**NWT Regional Office Cost Centre
Determination of Test Year
Allowance for Working Capital
($000)**

	Per Submission	NEB Adjustments	NEB Recommended
Net Cost of Service	188	(6)	182
Less: Depreciation	7	(3)	4
Cash Cost of Service	**181**	**(3)**	**178**
Cash Working Capital $181 x (25.425/365)	13	(13)	—
Cash Working Capital $178 x (31.59/365)[1]	—	16	16
Operating Materials & Supplies Inventory	8	—	8
Prepaid Expenses	—	—	—
Allowance for Working Capital	**21**	**3**	**24**

1 Refer to Section 4.12.1

Table F-13

**NWT Hydro Rate Zone
Test Year Rate Base Summary
($000)**

	Per Submission	NEB Adjustments	NEB Recommended
Plant in Service[1]	74,495	(5,599)	68,896
Less: Accumulated Depreciation[2]	32,757	(5,238)	27,519
Net Plant in Service	41,738	(361)	41,377
Allowance for Working Capital[3]	1,453	116	1,569
Rate Base	**43,191**	**(245)**	**42,946**

1 Refer to Table F-24
2 Refer to Table F-24
3 Refer to Table F-14

Table F-14

NWT Hydro Rate Zone
Determination of Test Year
Allowance for Working Capital
($000)

	Per Submission	NEB Adjustments	NEB Recommended
Net Cost of Service	10,576	(813)	9,763
Less: Depreciation	2,927	(659)	2,268
Cash Cost of Service	**7,649**	**(154)**	**7,495**
Cash Working Capital $7,649 x (25.425/365)	533	(533)	—
Cash Working Capital $7,495 x (31.59/365)[1]	—	649	649
Operating Materials & Supplies Inventory	920	—	920
Prepaid Expenses	—	—	—
Allowance for Working Capital	**1,453**	**116**	**1,569**

1 Refer to Section 4.12.1

Table F-15

NWT Diesel Rate Zone
Test Year Rate Base Summary
($000)

	Per Submission	NEB Adjustments	NEB Recommended
Plant in Service[1]	77,452	(1,590)	75,862
Less: Accumulated Depreciation[2]	35,566	(4)	35,562
Net Plant in Service	41,886	(1,586)	40,300
Unamortized Balance of Deferred Credit[3]	—	(4,436)	(4,436)
Allowance for Working Capital[4]	11,181	602	11,783
Rate Base	**53,067**	**(5,420)**	**47,647**

1 Refer to Table F-25
2 Refer to Table F-25
3 Refer to Table F-28
4 Refer to Table F-16

Table F-16

**NWT Diesel Rate Zone
Determination of Test Year
Allowance for Working Capital
($000)**

	Per Submission	NEB Adjustments	NEB Recommended
Net Cost of Service	42,103	(696)	41,407
Less: - Depreciation	4,575	(105)	4,470
- Amortization of Deferred Credit[1]	—	(228)	(228)
Cash Cost of Service	**37,528**	**(363)**	**37,165**
Cash Working Capital 37,528 x (25.425/365)	2,614	(2,614)	—
Cash Working Capital $37,165 x (31.59/365)[2]	—	3,216	3,216
Operating Materials & Supplies Inventory	8,567	—	8,567
Prepaid Expenses	—	—	—
Allowance for Working Capital	**11,181**	**602**	**11,783**

1 Refer to Table F-28
2 Refer to Section 4.12.1

Table F-17

**NWT Heat Rate Zone
Test Year Rate Base Summary
($000)**

	Per Submission	NEB Adjustments	NEB Recommended
Plant in Service[1]	6,540	(255)	6,285
Less: Accumulated Depreciation[2]	2,843	(6)	2,837
Net Plant in Service	3,697	(249)	3,448
Unamortized Balance of Deferred Credit[3]	—	(791)	(791)
Allowance for Working Capital[4]	2,858	94	2,952
Rate Base	**6,555**	**(946)**	**5,609**

1 Refer to Table F-26
2 Refer to Table F-27
3 Refer to Table F-28
4 Refer to Table F-18

Table F-18

NWT Heat Rate Zone Determination of Test Year Allowance for Working Capital ($000)

	Per Submission	NEB Adjustments	NEB Recommended
Net Cost of Service	6,273	(127)	6,146
Less: - Depreciation	335	(13)	322
- Amortization of Deferred Credit[1]	—	(41)	(41)
Cash Cost of Service	**5,938**	**(73)**	**5,865**
Cash Working Capital 5,938 x (25.425/365)	414	(414)	—
Cash Working Capital \$5,865 x (31.59/365)[2]	—	508	508
Operating Material & Supplies Inventory	2,444	—	2,444
Prepaid Expenses	—	—	—
Allowance for Working Capital	**2,858**	**94**	**2,952**

1 Refer to Table F-28
2 Refer to Section 4.12.1

Table F-19

NWT Water & Sewerage Rate Zone Test Year Rate Base Summary ($000)

	Per Submission	NEB Adjustments	NEB Recommended
Plant in Service[1]	102	(14)	88
Less: Accumulated Depreciation[2]	25	(1)	24
Net Plant in Service	77	(13)	64
Unamortized Balance of Deferred Credit[3]	—	(42)	(42)
Allowance for Working Capital[4]	102	15	117
Rate Base	**179**	**(40)**	**139**

1 Refer to Table F-26
2 Refer to Table F-27
3 Refer to Table F-28
4 Refer to Table F-20

Table F-20

NWT Water & Sewerage Rate Zone
Determination of Test Year
Allowance for Working Capital
($000)

	Per Submission	NEB Adjustments	NEB Recommended
Net Cost of Service	675[1]	36	711
Less: - Depreciation	10	(6)	4
- Amortization of Deferred Credit[2]	—	(2)	(2)
Cash Cost of Service	**665**	**(44)**	**709**
Cash Working Capital $665 x (25.425/365)	46	(46)	—
Cash Working Capital $709 x (31.59/365)[3]	—	61	61
Operating Material & Supplies Inventory	56	—	56
Prepaid Expenses	—	—	—
Allowance for Working Capital	**102**	**15**	**117**

1 This amount was incorrectly stated by NCPC in its submission. The correct amount of $665,000 is shown in Table K-10 in Appendix K.
2 Refer to Table F-28
3 Refer to Section 4.12.1

Table F-21

Yukon Hydro Rate Zone
Plant Adjustments - Test Year
($000)

Description	Reference Section	Opening Balance (A)	Closing Balance (B)	Average Balance (A) + (B) / 2
Plant in Service				
1. Removal of the cost of Whitehorse No. 4	4.2	(61,344)	(61,344)	(61,344)
2. Disallowance of part of the construction costs of Aishihik	4.3	(12,000)	(12,000)	(12,000)
3. Removal of the cost of the proposed transmission line to Johnson's Crossing	4.7	(800)	(800)	(800)
4. Assignment of the cost of the modular diesel unit at Mayo, Yukon to correct rate zone	4.9	285	285	285
5. Revision of test year capital additions	4.10	—	(183)	(92)
TOTAL ADJUSTMENTS		**(73,859)**	**(74,042)**	**(73,951)**
Accumulated Depreciation				
1. Removal of the Whitehorse No. 4 amounts	4.2	(472)	(1,416)	(944)
2. Disallowance of part of the accumulated depreciation of Aishihik	4.3	(1,662)	(1,846)	(1,754)
3. Use of 65-year life to depreciate hydro production assets	4.5	(3,513)	(4,112)	(3,813)
4. Removal of the amount for the proposed transmission line to Johnson's Crossing	4.7	—	(27)	(13)
5. Assignment of the accumulated depreciation on the modular diesel unit at Mayo, Yukon to correct rate zone	4.9	171	199	185
TOTAL ADJUSTMENTS		**(5,476)**	**(7,202)**	**(6,339)**

Table F-22

Yukon Diesel Rate Zone
Plant Adjustments - Test Year
($000)

Description	Reference Section	Opening Balance (A)	Closing Balance (B)	Average Balance (A) + (B) / 2
Plant in Service				
1. Revision of test year capital additions	4.10	—	(119)	(60)
TOTAL ADJUSTMENTS		**—**	**(119)**	**(60)**

Table F-23

NWT Regional Office Cost Centre
Plant Adjustments - Test Year
($000)

Description	Reference Section	Opening Balance (A)	Closing Balance (B)	Average Balance $\frac{(A) + (B)}{2}$
Plant in Service				
1. Transfer of the cost of meters to the head office cost centre	4.8	(100)	(100)	(100)
TOTAL ADJUSTMENTS		**(100)**	**(100)**	**(100)**
Accumulated Depreciation				
1. Transfer of the amount for meters to the head office cost centre	4.8	(3)	(6)	(4)
TOTAL ADJUSTMENTS		**(3)**	**(6)**	**(4)**

Table F-24

NWT Hydro Rate Zone
Plant Adjustments - Test Year
($000)

Description	Reference Section	Opening Balance (A)	Closing Balance (B)	Average Balance $\frac{(A) + (B)}{2}$
Plant in Service				
1. Assignment of the cost of the diesel generating units at Clyde River, NWT and Inuvik, NWT to correct rate zone	4.9	(219)	(219)	(219)
2. Removal of the cost of the 7.5 MW diesel plant specifically assigned to Pine Point Mines	4.11	(5,380)	(5,380)	(5,380)
TOTAL ADJUSTMENTS		**(5,599)**	**(5,599)**	**(5,599)**
Accumulated Depreciation				
1. Use of 65-year life to depreciate hydro production assets	4.5	(1,461)	(1,582)	(1,522)
2. Assign accumulated depreciaton on diesel generating units at Clyde River, NWT and Inuvik, NWT to correct rate zone	4.9	(219)	(219)	(219)
3. Removal of the amount for the 7.5 MW diesel plant specifically assigned to Pine Point Mines	4.11	(3,228)	(3,766)	(3,497)
TOTAL ADJUSTMENTS		**(4,908)**	**(5,567)**	**(5,238)**

Table F-25

NWT Diesel Rate Zone
Plant Adjustments - Test Year
($000)

Description	Reference Section	Opening Balance (A)	Closing Balance (B)	Average Balance $\frac{(A) + (B)}{2}$
Plant in Service				
1. Treatment of Inuvik powerhouse replacement	4.6.3	(1,524)	(1,524)	(1,524)
2. Assignment of the cost of diesel generating units at Clyde River, NWT and Inuvik, NWT to correct rate zone	4.9	219	219	219
3. Assignment of the cost of the modular diesel unit at Mayo, Yukon to correct rate zone	4.9	(285)	(285)	(285)
TOTAL ADJUSTMENTS		**(1,590)**	**(1,590)**	**(1,590)**
Accumulated Depreciation				
1. Treatment of Inuvik powerhouse replacement	4.6.3	—	(76)	(38)
2. Assignment of accumulated depreciation on diesel generating units at Clyde River, NWT and Inuvik, NWT to correct rate zone	4.9	219	219	219
3. Assignment of accumulated depreciation on the modular diesel unit at Mayo, Yukon to correct rate zone	4.9	(171)	(199)	(185)
TOTAL ADJUSTMENTS		**48**	**(56)**	**(4)**

Table F-26

Treatment of Inuvik Powerhouse Replacement Test Year Average Plant in Service ($000)

	Per Submission	NEB Adjustments	NEB Recommended[1]
Total Plant in Service			
Production Plant[2]	6,089	(1,343)	4,746
Other Plant	1,704	(450)	1,254
Total	**7,793**	**(1,793)**	**6,000**
Plant in Service by Rate Zone			
NWT Diesel Rate Zone			
Production Plant	4,871	(1,074)	3,797
Other Plant	1,704	(450)	1,254
Total	**6,575**	**(1,524)**	**5,051**
NWT Heat Rate Zone			
Production Plant	1,157	(255)	902
Other Plant	—	—	—
Total	**1,157**	**(255)**	**902**
NWT Water & Sewerage Rate Zone			
Production Plant	61	(14)	47
Other Plant	—	—	—
Total	**61**	**(14)**	**47**

1 The $6 million in plant was allocated to "Production" and "Other" in the same proportion as the original cost of the destroyed assets.

2 Production plant is allocated per the submission to the rate zones as follows: Diesel 80%; Heat 19%; Water & Sewerage 1%.

Table F-27

Treatment of Inuvik Powerhouse Replacement Test Year Accumulated Depreciation ($000)

	Per Submission			NEB Recommended			
	Opening Balance (A)	Closing Balance (B)	Average Balance (C)	Opening Balance (D)	Closing Balance (E)	Average Balance (F)	NEB Adjustments (F)-(C)
Total Accumulated Depreciation[1]							
Production Plant	—	305	153	—	237	119	(34)
Other Plant	—	85	43	—	63	32	(11)
Total	**—**	**390**	**196**	**—**	**300**	**151**	**(45)**
Accumulated Depreciation By Rate Zone							
NWT Diesel Rate Zone							
Production Plant	—	244	122	—	190	95	(27)
Other Plant	—	85	43	—	63	32	(11)
Total	**—**	**329**	**165**	**—**	**253**	**127**	**(38)**
NWT Heat Rate Zone							
Production Plant	—	58	29	—	45	23	(6)
Other Plant	—	—	—	—	—	—	—
Total	**—**	**58**	**29**	**—**	**45**	**23**	**(6)**
NWT Water & Sewerage Rate Zone							
Production Plant	—	3	2	—	2	1	(1)
Other Plant	—	—	—	—	—	—	—
Total	**—**	**3**	**2**	**—**	**2**	**1**	**(1)**

1 Per NCPC's submission, the powerhouse is assumed to have an expected life of 20 years.

Table F-28

Treatment of Inuvik Powerhouse Replacement
Test Year Unamoritzed Balance of Deferred Credit[1]
($000)

	Opening Balance (A)	Test Year Amortization (B)	Closing Balance (C)	Average Balance ((A) + (C))/2
Total Unamortized Balance of Deferred Credit				
Production Plant	4,275	(214)	4,061	4,168
Other Plant	1,130	(57)	1,073	1,101
Total	**5,405[2]**	**(271)**	**5,134**	**5,269**
Unamortized Balance of Deferred Credit by Rate Zone				
NWT Diesel Rate Zone				
Production Plant	3,420	(171)	3,249	3,335
Other Plant	1,130	(57)	1,073	1,101
Total	**4,550**	**(228)**	**4,322**	**4,436**
NWT Heat Rate Zone				
Production Plant	812	(41)	771	791
Other Plant	—	—	—	—
Total	**812**	**(41)**	**771**	**791**
NWT Water & Sewerage Rate Zone				
Production Plant	43	(2)	41	42
Other Plant	—	—	—	—
Total	**43**	**(2)**	**41**	**42**

1 Deferred credit amortized over a 20-year period on a straight-line basis.

2 "Excess of Insurance Proceeds Over the Net Book Value of Assets Destroyed by Fire" (see Section 4.6.3).

Table F-29

Assets Specially Classified
Whitehorse No.4
Test Year
($000)

	Opening Balance (A)	Closing Balance (B)	Average Balance $\frac{(A) + (B)}{2}$
Plant in Service			
Per Submission	**61,344**	**61,344**	**61,344**
NEB Recommended Adjustments			
- Removal of fish hatchery costs	(1,000)	(1,000)	(1,000)
- Removal of fish screen costs	(850)	(850)	(850)
- Loans returned to Government of Canada	(975)	(975)	(975)
Total Adjustments	**(2,825)**	**(2,825)**	**(2,825)**
NEB Recommended Plant in Service	58,519	58,519	58,519
Accumulated Depreciation[1]	(450)[2]	(1,350)	(900)
NEB Recommended Net Plant in Service	**58,069**	**57,169**	**57,619**

1 Accumulated depeciation is based on a 65-year asset life.

2 Per its submission, NCPC commenced depreciating these assets in the interim year and took only 50 percent of the annual charge of $900,000.

Derivation of Rate of Return on Rate Base per Submission[1]

	Balance March 31/85	Principal Payment 1985/86	Balance March 31/86	Interest Payment 1985/86	Weighted Interest Rate
NWT Hydro	$57,275,761.72	$1,895,944.27	$55,379,817.45	$5,021,239.63	8.7668%
Borrowing 1984/85	337,000.00	16,850.00	320,150.00	43,810.00	13.0000
	57,612,761.72	**1,912,794.27**	**55,699,967.45**	**5,065,049.63**	8.7916
NWT Diesel	49,571,044.12	3,511,753.69	46,059,290.43	4,720,106.35	9.5220
Borrowing 1984/85	4,555,000.00	227,750.00	4,327,250.00	592,150.00	13.0000
	54,126,044.12	**3,739,503.69**	**50,386,540.43**	**5,312,256.35**	9.8145
Regional Office	**177,543.88**	**10,607.18**	**166,936.70**	**16,306.99**	**9.1848**
Sub-total NWT	107,024,349.72	5,418,305.14	101,606,044.58	9,757,652.97	9.1172
Borrowing 1984/85	4,892,000.00	244,600.00	4,647,400.00	635,960.00	13.0000
TOTAL NWT	**$111,916,349.72**	**$5,662,905.14**	**$106,253,444.58**	**$10,393,612.97**	9.2869
Yukon Hydro	$123,250,785.64	$3,320,597.71	$119,930,187.93	$13,543,860.08	10.9889
Borrowing 1984/85	1,439,000.00	71,950.00	1,367,050.00	187,070.00	13.0000
	124,689,785.64	**3,392,547.71**	**121,297,237.93**	**13,730,930.08**	11.0121
Yukon Diesel	2,040,523.39	134,460.87	1,906,062.52	237,309.22	11.6298
Borrowing 1984/85	347,000.00	17,350.00	329,650.00	45,110.00	13.0000
	2,387,523.39	**151,810.87**	**2,235,712.52**	**282,419.22**	11.8290
Regional Office	**43,127.27**	**1,370.89**	**41,756.38**	**4,258.82**	**9.8750**
Sub-total Yukon	125,334,436.30	3,456,429.47	121,878,006.83	13,785,428.12	10.9989
Borrowing 1984/85	1,786,000.00	89,300.00	1,696,700.00	232,180.00	13.0000
TOTAL YUKON	**$127,120,436.30**	**$3,545,729.47**	**$123,574,706.83**	**$14,017,608.12**	11.1145
Field, B.C.	**$110,874.71**	**$12,385.26**	**$98,489.45**	**$6,745.84**	6.0843
Head Office	**$1,298,196.34**	**$114,003.61**	**$1,184,192.73**	**$103,705.68**	7.9885
Sub-total NCPC	$233,767,857.07	$9,001,123.48	$224,766,733.59	$23,653,532.61	10.1184
Borrowing 1984/85	6,678,000.00	333,900.00	6,344,100.00	868,140.00	13.0000
TOTAL NCPC	**$240,445,857.07**	**$9,335,023.48**	**$231,110,833.59**	**$24,521,672.61**	10.1984

1 Source: Exhibit B-7, response to question 21(b).

Derivation of Rate of Return on Rate Base as Revised[1]

	Balance March 31/85	Principal Payment 1985/86	Balance March 31/86	Interest Payment 1985/86	Weighted Interest Rate
NWT Hydro	$53,025,048.59	$1,797,112.80	$51,227,935.79	$4,609,165.62	8.6924%
NWT Diesel	49,571,044.12	3,511,753.69	46,059,290.43	4,720,106.35	9.5219
Regional Office	117,165.65	8,687.94	108,477.71	10,344.64	8.8291
TOTAL NWT	**$102,713,258.36**	**$5,317,554.43**	**$97,395,703.93**	**$9,339,616.61**	9.0929
Yukon Hydro	$122,275,785.64	$3,295,597.71	$118,980,187.93	$13,391,516.33	10.9519
Yukon Diesel	2,040,523.39	134,460.87	1,906,062.52	237,309.22	11.6298
Regional Office	—	—	—	—	—
TOTAL YUKON	**$124,316,309.03**	**$3,430,058.58**	**$120,886,250.45**	**$13,628,825.55**	10.9630
Field, B.C.	**$110,874.71**	**$12,385.26**	**$98,489.45**	**$6,745.84**	6.0842
Head Office	**$1,298,196.34**	**$114,003.61**	**$1,184,192.73**	**$103,705.68**	7.9884
Sub-total NCPC	$228,438,638.44	$8,874,001.88	$219,564,636.56	$23,078,893.68	10.1029
Borrowing 1984/85	5,000,000.00	250,000.00	4,750,000.00	581,250.00	11.6250
TOTAL NCPC	**$233,438,638.44**	**$9,124,001.88**	**$224,314,636.56**	**$23,660,143.68**	10.1355

1 Subsequent to the completion of the inquiry, NCPC prepaid principal of approximately $5,329,000 on the then outstanding balance of loans. This prepayment, together with revised new borrowings as at 31 March 1985 of $5,000,000, resulted in a reduced composite interest rate for the test year of 10.1355 percent. The composition of the $5,329,000 is illustrated on page 3 of Appendix G.

Difference Between Loans Outstanding per Submission and as Revised

	Balance March 31/85	Principal Payment 1985/86	Balance March 31/86	Interest Payment 1985/86
Loans outstanding per submission (exclusive of 1984/85 borrowings)	$233,767,857.07	$9,001,123.48	$224,766,733.59	$23,653,532.61
Loans outstanding as revised (exclusive of I984/85 borrowings)	228,438,638.44	8,874,001.88	219,564,636.56	23,078,893.68
Difference	**$5,329,218.63**	**$127,121.60**	**$5,202,097.03**	**$574,638.93**

Reconciliation of Difference Between Loans Outstanding per Submission and as Revised

Plant	Loan No.	Balance March 31/85	Principal Payment 1985/86	Balance March 31/86	Interest Payment 1985/86
NWT Regional Office	175-97	$60,378.23	$1,919.24	$58,458.99	$5,962.35
Yukon Regional Office	I75-98	43,127.27	1,370.89	41,756.38	4,258.82
Whitehorse	A231-05	975,000.00[1]	25,000.00	950,000.00	152,343.75
Yellowknife	001-01	60,053.33	9,025.35	51,027.98	2,477.20
Yellowknife	006-01	107,855.48	3,538.05	104,317.43	8,695.85
Yellowknife	161-01	39,239.02	857.47	38,381.55	3,139.12
Yellowknife	D162-01	31,430.18	1,315.48	30,114.70	2,454.35
Yellowknife	B219-01	242,876.02	21,725.32	221,150.70	22,769.63
Snare Cascades	202-60	92,3I2.73	1,262.59	91,050.14	8,654.32
Snare Cascades	203-60	888,510.59	12,152.38	876,358.21	83,297.87
Snare Cascades	223-60	450,755.59	5,961.21	444,794.38	43,385.23
Snare Cascades	226-60	293,294.20	4,218.12	289,076.08	26,396.48
Snare Forks	212-49	1,523,953.99	20,340.55	1,503,613.44	158,110.22
Pine Point Mines	A228-63	520,432.00	18,434.95	501,997.05	52,693.74
Total		**$5,329,218.63**	**$127,121.60**	**$5,202,097.03**	**$574,638.93**

1 Principal prepaid re Whitehorse No. 4 (see Section 4.2.4.1).

Appendix H

Summary of Loans Associated with Whitehorse No. 4 to be Deferred[1]

Loan No.	Original Amount of Loan	Principal Outstanding as of 31 March 1985	March 1986 Payment Principal	March 1986 Payment Interest	Principal Outstanding as of 31 March 1986	Interest Rate
B230-05[2]	$2,575,682.13	$661,290.08	$16,956.16	$90,927.39	$644,333.92	13.750%
A231-05[3]	5,537,662.87	4,424,221.30	113,441.57	691,284.58	4,310,779.73	15.625
A232-05	7,438,609.58	7,252,644.34	185,965.24	1,087,896.65	7,066,679.10	15.000
B232-05	11,136,034.73	10,857,633.86	278,400.87	1,574,356.91	10,579,232.99	14.500
C232-05	3,819,257.59	3,723,776.15	95,481.44	474,781.46	3,628,294.71	12.750
D232-05	16,748,480.00	16,329,768.00	418,712.00	1,959,572.16	15,911,056.00	12.000
A233-05	14,088,000.00	13,735,800.00	352,200.00	1,734,144.75	13,383,600.00	12.625
	$61,343,726.90	**$56,985,133.73**	**$1,461,157.28**	**$7,612,963.90**	**$55,523,976.45**	

1 Source: a) Exhibit B-5, Statements 724-726, page 4 of 5.
b) Transcript Page 639, Volume 5, lines 2-10.

2 Reflects write-off of $1,850,000 (see Appendix I for details).

3 Principal prepaid in the amount of $975,000.

Summary of Loans to be Forgiven and Written Off

Description	Loan No.	Principal Outstanding as at 31 March 1985	Principal Payment	Interest Payment	Principal Outstanding as at 31 March 1986
1. Whitehorse No. 4	B230-05	$1,850,000.00	$47,435.89	$254,375.00	$1,802,564.11
2. Aishihik	216-57	2,641,992.68	40,660.76	267,501.76	2,601,331.92
	215-57	492,588.41	7,581.03	49,874.58	485,007.38
	211-57	963,446.05	14,385.47	99,957.53	949,060.58
	174-57	2,393,983.56	37,404.53	239,398.36	2,356,579.03
	172-57	2,095,800.73	32,745.60	209,580.07	2,063,055.13
	171-57	1,658,345.57	25,910.63	165,834.56	1,632,434.94
3. Assets Not in Service					
(a) Aishihik[1]	166-57	1,530,000.00	29,030.36	128,137.50	1,500,969.64
(b) Inuvik[1]	184-06	94,742.91	16,029.26	7,934.72	78,713.65
	185-06	296,396.27	40,023.02	24,823.19	256,373.25
	100-06	129,311.52	3,288.44	10,991.48	126,023.08
	A194-06	122,442.35	7,162.01	10,407.60	115,280.34
	B194-06	59,246.36	3,465.48	5,035.94	55,780.88
	101-06	823,860.59	21,469.39	67,968.50	802,391.20
(ç) Cumulative Value of General Assets Removed from Service[2]					
Head Office	A160-00	6,000.00	579.56	435.00	5,420.44
Yukon Diesel	E232-14	35,000.00	1,944.45	4,112.49	33,055.55
Yukon Hydro	009-05	230,500.40	2,930.05	19,592.53	227,570.35
	166-57	751,499.60	14,259.02	62,938.09	737,240.58
Field, B.C.	002-09	7,000.00	285.34	468.13	6,714.66
NWT Regional Office	180-97	8,505.15	566.52	744.20	7,938.63
	220-97	11,494.85	1,235.09	1,077.64	10,259.76
NWT Diesel	A221-06	477,452.16	22,835.60	45,954.77	454,616.56
	B221-06	193,970.92	8,108.94	18,669.70	185,861.98
	A221-07	109,084.03	5,217.26	10,499.34	103,866.77
	B221-07	62,933.09	3,009.96	6,057.31	59,923.13
	C221-07	25,173.20	1,203.99	2,422.92	23,969.21
	D221-07	109,084.03	5,217.26	10,499.34	103,866.77
	E221-07	25,173.20	1,203.99	2,422.92	23,969.21

1 Source: Exhibit B-4, page 3-42.

2 Source: Exhibit B-20, response to question 41(a).

Summary of Loans to be Forgiven and Written Off

Description	Loan No.	Principal Outstanding as at 31 March 1985	Principal Payment	Interest Payment	Principal Outstanding as at 31 March 1986
NWT Diesel (cont'd)	A219-11	$128,834.63	$13,842.93	$12,078.25	$114,991.70
	B219-11	4,746.53	510.00	444.99	4,236.53
	A221-11	25,173.20	1,203.99	2,422.92	23,969.21
	B221-11	9,230.14	441.47	888.40	8,788.67
	219-15	132,225.02	14,207.22	12,396.10	118,017.80
	221-15	10,908.38	521.73	1,049.93	10,386.65
	220-21	37,718.50	4,052.74	3,536.11	33,665.76
	223-21	24,799.50	1,204.01	2,324.95	23,595.49
	A219-22	44,027.55	4,730.65	4,127.58	39,296.90
	222-22	3,332.94	159.41	320.80	3,173.53
	221-23	5,034.68	240.79	484.59	4,793.89
	220-24	25,512.60	1,220.22	2,455.59	24,292.38
	220-25	12,756.34	610.10	1,227.80	12,146.24
	223-25	32,114.32	829.53	3,050.86	31,284.79
	A220-26	8,504.21	406.74	818.53	8,097.47
	B220-26	21,260.58	1,016.84	2,046.33	20,243.74
	A221-27	21,816.81	1,043.45	2,099.87	20,773.36
	B221-27	16,782.13	802.66	1,615.28	15,979.47
	C221-27	5,873.73	280.93	565.35	5,592.80
	222-29	41,662.03	1,992.62	4,009.97	39,669.41
	221-31	20,977.73	1,003.31	2,019.11	19,974.42
	221-32	30,207.87	1,444.78	2,907.51	28,763.09
	B223-34	35,784.44	924.35	3,399.52	34,860.09
	222-36	55,827.16	2,670.11	5,373.36	53,157.05
	A220-40	54,353.27	1,996.60	5,231.50	52,356.67
	B220-40	8,504.21	406.74	818.53	8,097.47
	221-43	134,257.24	6,421.25	12,922.26	127,835.99
	221-45	22,655.88	1,083.59	2,180.63	21,572.29
	A221-46	50,346.42	2,407.98	4,845.84	47,938.44
	B221-46	16,782.13	802.66	1,615.28	15,979.47
	C221-46	10,908.38	521.73	1,049.93	10,386.65
	A221-48	20,138.56	963.19	1,938.34	19,175.37
	B221-48	8,391.07	401.33	807.64	7,989.74
	A221-50	4,195.57	200.66	403.82	3,994.91
	B221-50	4,195.57	200.66	403.82	3,994.91
	A220-53	58,039.70	2,426.35	5,586.32	55,613.35
	B220-53	4,252.14	203.36	409.27	4,048.78
	221-55	1,678.27	80.26	161.53	1,598.01
	B200-88	719,319.94	64,343.33	67,436.24	654,976.61
NWT Hydro	A177-01	40,974.70	2,364.87	3,585.29	38,609.83
	B177-01	40,974.70	2,364.87	3,585.29	38,609.83
	180-01	102,126.00	5,894.22	8,936.03	96,231.78
	181-01	280,887.29	16,211.46	24,577.64	264,675.83
	182-01	93,037.31	5,369.66	8,140.76	87,667.65
NWT Heat/Water	179-06	283,839.04	18,906.40	24,835.92	264,932.64
	227-06	325,160.96	14,283.24	28,858.04	310,877.72
(d) Assets Not Used and Useful					
Yukon Diesel	004-14	36,317.48	1,286.39	3,086.99	35,031.09
Yukon Hydro	166-57[1]	492,000.00	9,335.25	41,205.00	482,664.75

1 Amount for write-off determined on the basis of the Commission's response to question 21 of Exhibit B-10.

Summary of Loans to be Forgiven and Written Off

Description	Loan No.	Principal Outstanding as at 31 March 1985	Principal Payment	Interest Payment	Principal Outstanding as at 31 March 1986
NWT Diesel	006-04	$52,544.53	$1,861.15	$4,466.29	$50,683.38
	194-04	39,497.47	2,310.34	3,357.28	37,187.13
	003-08	23,181.37	821.10	1,970.42	22,360.27
	003-15	7,727.04	273.71	656.80	7,453.33
	003-16	34,772.01	1,231.66	2,955.62	33,540.35
	A194-16	112,313.49	5,745.14	9,546.65	106,568.35
	B194-16	24,488.49	1,432.40	2,081.52	23,056.09
	003-17	7,727.04	273.71	656.80	7,453.33
	197-17	117,251.23	6,293.47	10,017.35	110,957.76
	195-18	169,096.85	9,890.98	14,373.23	159,205.87
4. Under-recovery of Depreciation					
Yukon Diesel	191-14	46,152.59	6,311.18	3,634.52	39,841.41
Yukon Hydro	008-05	1,442,020.00	19,367.87	117,164.13	1,422,652.13
	166-57	3,367,000.49	63,885.77	281,986.29	3,303,114.72
	A161-05	48,853.06	1,067.56	3,908.24	47,785.50
	B161-05	97,706.27	2,135.09	7,816.50	95,571.18
	161-57	1,815,621:79	36,007.87	145,249.74	1,779,613.92
	B163-57	2,087,271.29	41,395.29	166,981.70	2,045,876.00
	164-57	2,335,894.19	46,326.02	186,871.54	2,289,568.17
	162-57	628,366.49	12,553.84	49,876.59	615,812.65
	190-05	46,208.23	6,318.77	3,638.90	39,889.46
NWT Regional Office	165-97	42,653.17	1,029.12	3,412.25	41,624.05
NWT Diesel	008-06	89,152.82	2,878.69	7,355.11	86,274.13
	101-06	195,503.80	5,094.73	16,129.06	190,409.07
	006-07	495,061.36	15,985.03	40,842.56	479,076.33
	008-07	521,557.41	17,019.11	42,376.54	504,538.30
	184-04	236,857.43	40,073.13	19,836.81	196,784.30
	185-17	11,829.33	2,001.36	990.71	9,827.97
	183-19	4,758.90	805.12	398.56	3,953.78
	184-23	15,632.56	2,644.83	1,309.23	12,987.73
	184-29	14,211.41	2,404.39	1,190.21	11,807.02
	185-32	82,805.15	14,009.56	6,934.93	68,795.59
	184-35	29,670.92	4,006.54	2,484.94	25,664.38
	183-37	38,735.23	5,230.49	3,244.08	33,504.74
	183-38	47,588.27	8,051.32	3,985.52	39,536.95
	184-38	8,053.12	1,362.49	674.45	6,690.63
	183-42	19,035.40	3,220.52	1,594.21	15,814.88
	185-42	4,731.69	800.55	396.28	3,931.14
	183-47	59,592.64	8,046.92	4,990.88	51,545.72
	185-52	8,891.85	1,200.70	744.69	7,691.15
	009-06	40,839.67	1,339.69	3,292.70	39,499.98
	102-06	499,487.46	13,256.84	40,271.18	486,230.62
	003-07	81,348.81	2,668.53	6,558.75	78,680.28
	004-07	122,023.24	4,002.80	9,838.12	118,020.44
	004-17	97,117.27	3,185.82	7,830.08	93,931.45
	165-25	42,653.17	1,029.12	3,412.25	41,624.05
	165-28	83,344.26	2,010.90	6,667.54	81,333.36
	165-32	83,344.26	2,010.90	6,667.54	81,333.36
	165-44	85,306.35	2,058.23	6,824.51	83,248.12
	A165-16	77,098.69	3,198.21	6,119.71	73,900.48
	165-45	38,549.34	1,599.11	3,059.85	36,950.23
	195-18	99,079.29	5,795.44	8,421.74	93,283.85
	002-19	77,271.32	2,737.00	6,568.06	74,534.32
	002-20	251,131.94	8,895.23	21,346.21	242,236.71
	197-21	39,283.73	2,297.82	3,339.12	36,985.91

Summary of Loans to be Forgiven and Written Off

Description	Loan No.	Principal Outstanding as at 31 March 1985	Principal Payment	Interest Payment	Principal Outstanding as at 31 March 1986
NWT Diesel (cont'd)	A196-22	$122,885.51	$7,187.92	$10,445.27	$115,697.59
	B196-22	18,905.43	1,105.84	1,606.96	17,799.59
	A196-27	143,386.30	7,334.61	12,187.84	136,051.69
	B196-27	3,938.59	230.39	334.78	3,708.20
	196-28	43,325.02	2,534.20	3,682.63	40,790.82
	196-32	370,231.80	21,655.95	31,469.70	348,575.85
	197-33	39,283.73	2,297.82	3,339.12	36,985.91
	A197-37	104,494.75	6,112.21	8,882.05	98,382.54
	B197-37	268,200.39	13,719.22	22,797.03	254,481.17
	194-38	15,798.96	924.14	1,342.91	14,874.82
	A197-40	58,925.63	3,446.73	5,008.68	55,478.90
	B197-40	173,427.88	6,909.79	14,741.37	166,518.09
	C197-40	15,713.42	919.14	1,335.64	14,794.28
	197-47	10,999.48	643.38	934.96	10,356.10
	196-48	11,815.87	691.15	1,004.35	11,124.72
	197-50	41,640.73	2,435.70	3,539.46	39,205.03
	195-55	126,200.52	7,381.85	10,727.04	118,818.67
	188-04	111,074.82	15,189.01	8,747.14	95,885.81
NWT Hydro	003-13	495,061.36	15,985.03	40,842.56	479,076.33
	184-02	80,531.51	13,624.87	6,774.51	66,906.64
	185-13	18,926.93	3,202.18	1,585.13	15,724.75
	161-01	9,614.04	210.09	769.12	9,403.95
	A165-13	56,178.57	1,013.01	4,494.29	55,165.56
	132-49	168,535.72	3,039.04	13,482.86	165,496.68
	161-49	1,276,124.74	23,011.17	102,089.98	1,253,113.57
	006-01	111,786.19	3,667.00	9,012.76	108,119.19
	004-13	412,748.80	13,539.69	33,277.87	399,209.11
	005-01	540,899.87	19,158.91	45,976.49	521,740.96
	196-02	90,588.62	5,298.80	7,700.03	85,289.82
	003-10	3,090.91	109.47	262.73	2,981.44
	194-10	15,798.96	924.14	1,342.91	14,874.82
Total Loans to be Forgiven and Written Off		**$41,881,504.71**	**$1,269,981.14**	**$3,778,057.44**	**$40,611,523.57**

Appendix J

Derivation of Recommended Rate of Return on Rate Base

	Balance March 31/85	Principal Payment 1985/86	Balance March 31/86	Interest Payment 1985/86	Weighted Interest Rate
NWT Hydro	$49,187,162.37	$1,662,124.32	$47,525,038.05	$4,292,729.37	8.7273%
NWT Diesel	38,689,647.68	2,880,735.35	35,808,912.33	3,777,344.99	9.7632
Regional Office	54,512.48	5,857.21	48,655.27	5,110.55	9.3750
TOTAL NWT	**$87,931,322.53**	**$4,548,716.88**	**$83,382,605.65**	**$8,075,184.91**	9.1835
Yukon Hydro	$38,321,553.10	$1,343,703.76	$36,977,849.34	$3,276,663.82	8.5504
Yukon Diesel	1,923,053.32	124,918.85	1,798,134.47	226,475.22	11.7769
Regional Office	—	—	—	—	—
TOTAL YUKON	**$40,244,606.42**	**$1,468,622.61**	**$38,775,983.81**	**$3,503,139.04**	8.7046
Field, B.C.	**$103,874.71**	**$12,099.92**	**$91,774.79**	**$6,277.71**	6.0435
Head Office	**$1,292,196.34**	**$113,424.05**	**$1,178,772.29**	**$103,270.68**	7.9919
Sub-total NCPC	129,572,000.00	6,142,863.46	123,429,136.54	11,687,872.34	9.0204
Borrowing 1984/85	5,000,000.00	250,000.00	4,750,000.00	581,250.00	11.6250
Interest-free Loan	7,500,000.00	—	7,500,000.00	—	—
TOTAL NCPC	**$142,072,000.00**	**$6,392,863.46**	**$135,679,136.54**	**$12,269,122.34**	8.6358

Details of Adjustments to Test Year Revenue Requirement

Details of adjustments recommended by the Board to the test year revenue requirement for each cost centre and rate zone are shown in Tables K-1 to K-10 in this appendix.

Table K-1

Head Office Test Year Revenue Requirement ($ 000)

Particulars	Per Submission	NEB Adjustments	NEB Recommended
Cost of Service			
Administration and Overhead			
Salaries and Wages	4,251	—	4,251
Fuel	—	—	—
Supplies and Services	1,933	(58)[1]	1,875
Travel Expense	466	(14)[1]	452
Total	6,650	(72)	6,578
Depreciation Expense	102	—	102
TOTAL COST OF SERVICE	6,752	(72)	6,680
Less: Transfers Out	694[2]	—	694
Interest Income	1,089	(589)[3]	500
NET COST OF SERVICE	4,969	517	5,486
Return	215	(13)[4]	202
TOTAL REVENUE REQUIREMENT	5,184	504	5,688
Less: Other Deductions	—	—	—
NET REVENUE REQUIREMENT	**5,184**	**504**	**5,688**
Allocation of Head Office Net Revenue Requirement to Rate Zones[5]			
Yukon - Hydro	617	17	634
- Diesel	169	36	205
Total Yukon	786	53	839
NWT - Hydro	1,067	127	1,194
- Diesel	2,834	574	3,408
- Heat	345	(147)	198
- Water & Sewerage	124	(110)	14
Total NWT	4,370	444	4,814
Field, B.C.	28	7	35
NET REVENUE REQUIREMENT	**5,184**	**504**	**5,688**

1 Reflects downward adjustment of 3 percent; see Section 6.2.5.
2 Administration and overhead costs allocated to capital projects.
3 Reflects Board's recommendation in Section 6.6.1.
4 Reflects Board's recommendations in Sections 4.13 and 5.4.
5 For a description of the method of allocation see Section 6.6.

Table K-2

Yukon Regional Office Test Year Revenue Requirement
($ 000)

Particulars	Per Submission	NEB Adjustments	NEB Recommended
Cost of Service			
Administration and Overhead			
Salaries and Wages	305	—	305
Fuel	—	—	—
Supplies and Services	39	(1)[1]	38
Travel Expense	59	(2)[1]	57
Total	403	(3)	400
Depreciation Expense	2	—	2
TOTAL COST OF SERVICE	405	(3)	402
Less: Transfers Out	—	—	—
NET COST OF SERVICE	405	(3)	402
Return	5	—[2]	5
TOTAL REVENUE REQUIREMENT	410	(3)	407
Less: Other Deductions	—	—	—
NET REVENUE REQUIREMENT	**410**	**(3)**	**407**

Allocation of Yukon Regional Office Net Revenue Requirement to Rate Zones[3]

Particulars	Per Submission	NEB Adjustments	NEB Recommended
Yukon - Hydro	322	(2)	320
- Diesel	88	(1)	87
Total	**410**	**(3)**	**407**

1 Reflects downward adjustment of 3 percent; see Section 6.2.5.
2 Reflects Board's recommendations in Sections 4.13 and 5.4.
3 For a description of the method of allocation see Section 6.7.

Table K-3

NWT Regional Office Test Year Revenue Requirement
($ 000)

Particulars	Per Submission	NEB Adjustments	NEB Recommended
Cost of Service			
Administration and Overhead			
Salaries and Wages	88	—	88
Fuel	—	—	—
Supplies and Services	61	(2)[1]	59
Travel Expense	32	(1)[1]	31
Total	181	(3)	178
Depreciation Expense	7	(3)[2]	4
TOTAL COST OF SERVICE	188	(6)	182
Less: Transfers Out	—	—	—
NET COST OF SERVICE	188	(6)	182
Return	18	(11)[3]	7
TOTAL REVENUE REQUIREMENT	206	(17)	189
Less: Other Deductions	—	—	—
NET REVENUE REQUIREMENT	**206**	**(17)**	**189**

Allocation of NWT Regional Office Net Revenue Requirement to Rate Zones[4]

Particulars	Per Submission	NEB Adjustments	NEB Recommended
NWT — Hydro	50	(1)	49
— Diesel	134	(4)	130
— Heat	16	(7)	9
— Water & Sewerage	6	(5)	1
Total	**206**	**(17)**	**189**

1 Reflects downward adjustment of 3 percent; see Section 6.2.5.
2 Reflects Board's recommendation in Section 4.13.
3 Reflects Board's recommendations in Sections 4.13 and 5.4.
4 For a description of the method of allocation see Section 6.7.

Table K-4

Yukon Hydro Rate Zone Test Year Revenue Requirement
($ 000)

Particulars	Per Submission	NEB Adjustments	NEB Recommended
Cost of Service			
Operating Expenses			
Salaries and Wages	1,396	—	1,396
Fuel	127	8[1]	135
Supplies and Services	2,028	(61)[2]	1,967
Travel Expense	229	(7)[2]	222
Total	3,780	(60)	3,720
Depreciation Expense			
Plant in Service	4,228	(1,726)[3]	2,502
Assets Specially Classified (Whitehorse No. 4)	—	900[4]	900
TOTAL COST OF SERVICE	8,008	(886)	7,122
Less: Transfers Out[5]	9	—	9
NET COST OF SERVICE	7,999	(886)	7,113
Return	11,059	(7,533)[6]	3,526
Regional Office Allocation	322	(2)[7]	320
Head Office Allocation	617	17[8]	634
TOTAL REVENUE REQUIREMENT	19,997	(8,404)	11,593
Less: Other Deductions[9]	47	—	47
NET REVENUE REQUIREMENT	**19,950**	**(8,404)**	**11,546**

1 Reflects Board's recommendation in Section 6.2.4.
2 Reflects downward adjustment of 3 percent; see Section 6.2.5.
3 Reflects the adjustments to plant in service including the removal of Whitehorse No. 4 from plant in service; see Section 4.13.
4 Depreciation on Whitehorse No. 4; see Section 4.13.
5 Employee facilities recoveries include rent paid to the Commission by employees occupying Commission provided housing.
6 Reflects Board's recommendations in Sections 4.13 and 5.4.
7 See Table K-2 of Appendix K.
8 See Table K-1 of Appendix K.
9 Other deductions arise from joint use assessment, connection charges and other miscellaneous revenues.

Table K-5

Yukon Diesel Rate Zone Test Year Revenue Requirement
($ 000)

Particulars	Per Submission	NEB Adjustments	NEB Recommended
Cost of Service			
Operating Expenses			
Salaries and Wages	381	—	381
Fuel	999	—	999
Supplies and Services	257	(8)[1]	249
Travel Expense	67	(2)[1]	65
Total	1,704	(10)	1,694
Depreciation Expense	143	—	143
TOTAL COST OF SERVICE	1,847	(10)	1,837
Less: Transfers Out[2]	17	—	17
NET COST OF SERVICE	1,830	(10)	1,820
Return	246	(40)[3]	206
Regional Office Allocation	88	(1)[4]	87
Head Office Allocation	169	36[5]	205
TOTAL REVENUE REQUIREMENT	2,333	(15)	2,318
Less: Other Deductions[5]	13	—	13
NET REVENUE REQUIREMENT	**2,320**	**(15)**	**2,305**

1 Reflects downward adjustment of 3 percent; see Section 6.2.5.
2 Employee facilities recoveries include (a) rent paid to the Commission by employees occupying Commission provided housing, and (b) a utility charge of $70 per month paid by each Northern employee to NCPC.
3 Reflects Board's recommendations in Sections 4.13 and 5.4.
4 See Table K-2 of Appendix K.
5 See Table K-1 of Appendix K.
6 Other deductions arise from joint use assessment, connection charges and other miscellaneous revenues.

Table K-6
Field, B.C. Rate Zone Test Year Revenue Requirement
($ 000)

Particulars	Per Submission	NEB Adjustments	NEB Recommended
Cost of Service			
Operating Expenses			
Salaries and Wages	62	—	62
Fuel	133	—	133
Supplies and Services	120	(4)[1]	116
Travel Expense	5	—[1]	5
Total	320	(4)	316
Depreciation Expense	2	—	2
TOTAL COST OF SERVICE	322	(4)	318
Less: Transfers Out[2]	4	—	4
NET COST OF SERVICE	318	(4)	314
Return	6	—[3]	6
Head Office Allocation	28	7[4]	35
TOTAL REVENUE REQUIREMENT	352	3	355
Less: Other Deductions[5]	6	—	6
NET REVENUE REQUIREMENT	**346**	**3**	**349**

1 Reflects downward adjustment of 3 percent; see Section 6.2.5.
2 Employee facilities recoveries include (a) rent paid to the Commission by employees occupying Commission provided housing, and (b) a utility charge of $70 per month paid by each Northern employee to NCPC.
3 Reflects Board's recommendations in Sections 4.13 and 5.4.
4 See Table K-1 of Appendix K.
5 Other deductions arise from joint use assessment, connection charges and other miscellaneous revenues.

Table K–7

NWT Hydro Rate Zone Test Year Revenue Requirement
($ 000)

Particulars	Per Submission	NEB Adjustments	NEB Recommended
Cost of Service			
Operating Expenses			
Salaries and Wages	2,410	—	2,410
Fuel	2,370	—	2,370
Supplies and Services	2,497	(141)[1,2]	2,356
Travel Expense	435	(13)[1]	422
Total	7,712	(154)	7,558
Depreciation Expense	2,927	(659)[3]	2,268
TOTAL COST OF SERVICE	10,639	(813)	9,826
Less: Transfers Out[4]	63	—	63
NET COST OF SERVICE	10,576	(813)	9,763
Return	4,405	(694)[5]	3,711
Regional Office Allocation	50	(1)[6]	49
Head Office Allocation	1,067	127[7]	1,194
TOTAL REVENUE REQUIREMENT	16,098	(1,381)	14,717
Less: Other Deductions[8]	94	—	94
NET REVENUE REQUIREMENT	**16,004**	**(1,381)**	**14,623**

1 Reflects downward adjustment of 3 percent; see Section 6.2.5.
2 Further reduced by $65,800 re capital asset appraisal program; see Section 6.2.5.
3 Reflects Board's recommendation in Section 4.13.
4 Employee facilities recoveries include rent paid to the Commission by employees occupying Commission provided housing.
5 Reflects Board's recommendations in Sections 4.13 and 5.4.
6 See Table K-3 of Appendix K.
7 See Table K-1 of Appendix K.
8 Other deductions arise from joint use assessment, connection charges and other miscellaneous revenues.

Table K-8

NWT Diesel Rate Zone Test Year Revenue Requirement
($ 000)

Particulars	Per Submission	NEB Adjustments	NEB Recommended
Cost of Service			
Operating Expenses			
Salaries and Wages	6,397	—	6,397
Fuel	21,183	—	21,183
Supplies and Services	9,127	(327)[1,2]	8,800
Travel Expense	1,190	(36)	1,154
Total	37,897	(363)	37,534
Depreciation Expense	4,575	(105)[3]	4,470
Amortization of Deferred Credit	—	(228)[4]	(228)
TOTAL COST OF SERVICE	42,472	(696)	41,776
Less: Transfers Out[5]	369	—	369
NET COST OF SERVICE	42,103	(696)	41,407
Return	5,412	(1,295)[6]	4,117
Regional Office Allocation	134	(4)[7]	130
Head Office Allocation	2,834	574[8]	3,408
TOTAL REVENUE REQUIREMENT	50,483	(1,421)	49,062
Less: Other Deductions[9]	251	—	251
NET REVENUE REQUIREMENT	**50,232**	**(1,421)**	**48,811**

1 Reflects downward adjustment of 3 percent; see Section 6.2.5.
2 Further reduced by $53,800 re capital asset appraisal program; see Section 6.2.5.
3 Reflects Board's recommendation in Section 4.13.
4 Annual amortization expense associated with the "Excess of Insurance Proceeds Over the Net Book Value of Assets Destroyed by Fire" at Inuvik; see Section 6.4.
5 Employee facilities recoveries include (a) rent paid to the Commission by employees occupying Commission provided housing, and (b) a utility charge of $70 per month paid by each Northern employee to NCPC.
6 Reflects Board's recommendations in Sections 4.13 and 5.4.
7 See Table K-3 of Appendix K.
8 See Table K-1 of Appendix K.
9 Other deductions arise from joint use assessment, connection charges and other miscellaneous revenues.

Table K-9

NWT Heat Rate Zone Test Year Revenue Requirement
($ 000)

Particulars	Per Submission	NEB Adjustments	NEB Recommended
Cost of Service			
Operating Expenses			
Salaries and Wages	778	—	778
Fuel	4,606	(56)[1]	4,550
Supplies and Services	509	(15)[2]	494
Travel Expense	72	(2)[2]	70
Total	5,965	(73)	5,892
Depreciation Expense	335	(13)[3]	322
Amortization of Deferred Credit	—	(41)[4]	(41)
TOTAL COST OF SERVICE	6,300	(127)	6,173
Less: Transfers Out[5]	27	—	27
NET COST OF SERVICE	6,273	(127)	6,146
Return	668	(183)[6]	485
Regional Office Allocation	16	(7)[7]	9
Head Office Allocation	345	(147)[8]	198
TOTAL REVENUE REQUIREMENT	7,302	(464)	6,838
Less: Other Deductions	—	—	—
NET REVENUE REQUIREMENT	**7,302**	**(464)**	**6,838**

1 Adjustment reflects the error acknowledged by NCPC in allocating fuel costs between the heat rate zone and the water & sewerage rate zone.
2 Reflects downward adjustment of 3 percent; see Section 6.2.5.
3 Reflects Board's recommendation in Section 4.13.
4 Annual amortization expense associated with the "Excess of Insurance Proceeds Over the Net Book Value of Assets Destroyed by Fire" at Inuvik; see Section 6.4.
5 Employee facilities recoveries include (a) rent paid to thè Commission by employees occupying Commission provided housing, and (b) a utility charge of $70 per month paid by each Northern employee to NCPC.
6 Reflects Board's recommendations in Sections 4.13 and 5.4.
7 See Table K-3 of Appendix K.
8 See Table K-1 of Appendix K.

Table K-10

NWT Water & Sewerage Rate Zone Test Year Revenue Requirement
($ 000)

Particulars	Per Submission	NEB Adjustments	NEB Recommended
Cost of Service			
Operating Expenses			
Salaries and Wages	280	—	280
Fuel	165	56[1]	221
Supplies and Services	208	(6)[2]	202
Travel Expense	17	(1)[2]	16
Total	670	49	719
Depreciation Expense	5	(1)[3]	4
Amortization of Deferred Credit	—	(2)[4]	(2)
TOTAL COST OF SERVICE	675	46	721
Less: Transfers Out[5]	10	—	10
NET COST OF SERVICE	665	46	711
Return	18	(6)[6]	12
Regional Office Allocation	6	(5)[7]	1
Head Office Allocation	124	(109)[8]	15
TOTAL REVENUE REQUIREMENT	813	(74)	739
Less: Other Deductions[9]	332	—	332
NET REVENUE REQUIREMENT	**481**	**(74)**	**407**

1 Adjustment reflects the error acknowledged by NCPC in allocating fuel costs between the heat rate zone and the water & sewerage rate zone.
2 Reflects downward adjustment of 3 percent; see Section 6.2.5.
3 Reflects Board's recommendation in Section 4.13.
4 Annual amortization expense associated with the "Excess of Insurance Proceeds Over the Net Book Value of Assets Destroyed by Fire" at Inuvik; see Section 6.4.
5 Employee facilities recoveries include (a) rent paid to the Commission by employees occupying Commission provided housing, and (b) a utility charge of $70 per month paid by each Northern employee to NCPC.
6 Reflects Board's recommendations in Sections 4.13 and 5.4.
7 See Table K-3 of Appendix K.
8 See Table K-1 of Appendix K.
9 This represents revenues from contract operation of the Fort McPherson water system for GNWT.

Details of Test Year Revenue Requirement by Customer Class for Each Rate Zone As Recommended by the Board

Tables L-1 to L-7 set out the recommended revenue requirement by customer class in each rate zone based on the cost allocation recommendations made by the Board in Chapter 7.

Table L-1

Yukon Hydro Rate Zone Test Year Revenue Requirement Recommended by Board (in dollars)

Customer Class	Demand Cost	Energy Cost	Customer Cost	Direct Assignment	Customer-Specific Charge (Credit)	Total Cost
Residential	611,765	162,305	121,130	—	—	895,200
Commercial	363,438	119,245	36,625	—	—	519,308
Wholesale	5,360,116[1]	2,150,173	57,077	—	—	7,567,366
Industrial (Primary)	867,793	397,482	22,801	—	248,211[2]	1,536,287
Industrial (Secondary)	515,429	480,290	4,591	—	—	1,000,310
Street Lighting	9,812	2,852	331	12,951	—	25,946
Yukon Hydro Rev. Req't						**11,544,417**

1 Includes $183,734 in specific charges re assets specifically assigned by NCPC in its submission to YECL.

2 To Cyprus Anvil: Includes $240,890 re costs of Whitehorse to Faro transmission line assigned specifically to Cyprus Anvil plus $7,321 re assets specifically assigned by NCPC in the submission.

Table L-2

Yukon Diesel Rate Zone Test Year Revenue Requirement Recommended by Board (in dollars)

Customer Class	Demand Cost	Energy Cost	Customer Cost	Direct Assignment	Customer-Specific Charge (Credit)	Total Cost
Residential	431,918	611,961	131,255	—	—	1,175,134
Commercial	385,278	665,142	42,512	—	—	1,092,932
Street Lighting	8,929	18,584	239	10,928	—	38,680
Yukon Diesel Rev. Req't.						**2,306,746**

Table L-3

Field, B.C. Rate Zone Test Year Revenue Requirement Recommended by Board (in dollars)

Customer Class	Demand Cost	Energy Cost	Customer Cost	Direct Assignment	Customer-Specific Charge (Credit)	Total Cost
Residential	29,841	75,416	26,616	—	—	131,873
Commercial	47,966	149,421	6,009	—	—	203,396
Street Lighting	2,117	7,612	159	3,355	—	13,243
Field, B.C. Rev. Req't.						**348,512**

Table L-4

NWT Hydro Rate Zone Test Year Revenue Requirement Recommended by Board (in dollars)

Customer Class	Demand Cost	Energy Cost	Customer Cost	Direct Assignment	Customer-Specific Charge (Credit)	Total Cost
Residential	1,124,687[1]	466,393	460,056	—	—	2,051,136
Commercial	742,771[2]	380,004	123,569	—	—	1,246,344
Wholesale	2,448,900	1,823,083	13,901	—	6,280 [3]	4,292,164
Industrial	3,477,328	3,455,929	40,920	—	(9,500)[4]	6,964,677
Street Lighting	22,294[5]	11,325	946	33,538	—	68,103
NWT Hydro Rev. Req't.						**14,622,424**
Payment from Pine Point Mines per contract					872,287	

1 Includes customer class-specific charge for wheeling on Con's line - $1,910.
2 Includes customer class-specific charge for wheeling on Con's line - $1,264.
3 Specific charge to ICG for wheeling on Con's line.
4 Specific credit to Con Mine for wheeling on its line.
5 Includes customer class-specific charge for wheeling on Con's line - $46.

Table L-5

NWT Diesel Rate Zone Test Year Revenue Requirement Recommended by Board (in dollars)

Customer Class	Demand Cost	Energy Cost	Customer Cost	Direct Assignment	Customer-Specific Charge (Credit)	Total Cost
Residential	7,511,305	14,394,635	2,195,058	—	—	24,100,998
Commercial	6,169,041	14,456,770	761,076	—	—	21,386,887
"Wholesale"[1]	422,784	1,211,613	15,648	—	—	1,650,045
Industrial (Primary)	163,554	466,005	82,779	—	—	712,338
Street Lighting	216,111	537,959	11,642	194,804	—	960,516
NWT Diesel Rev. Req't.						**48,810,784**

1 NCPC identified the customers in this class as Transport Canada and GNWT which are served at primary voltage.

Table L-6

NWT Heat Rate Zone Test Year Revenue Requirement Recommended by Board (in dollars)

	Inuvik	Frobisher Bay	Total
Total Plant Level Costs	3,686,342	2,179,032	5,865,374
Head Office Costs	104,194	94,657	198,851
Regional Office Costs	4,770	4,230	9,000
Depreciation	204,000	118,000	322,000
Amortization of Deferred Credit	(41,000)	—	(41,000)
Return on Rate Base	286,114	199,338	485,452
Total Revenue Requirement	**4,244,420**	**2,595,257**	**6,839,677**

Table L-7

NWT Water & Sewerage Rate Zone Test Year Revenue Requirement Recommended by Board (in dollars)

Total Plant Level Costs	466,550
Head Office Costs	14,496
Regional Office Costs	1,000
Depreciation	4,000
Amortization of Deferred Credit	(2,000)
Return on Rate Base	12,000
Fort McPherson - Contract Cost	243,000
Fort McPherson - Contract Revenue (includes overhead assessment)	(332,000)
Total Revenue Requirement	**407,046**